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Electric Power Supply and Demand for the Contiguous United States 1981-1990

July 1981

U.S. Department of Energy
Assistant Secretary for Environmental Protection,
Safety and Emergency Preparedness
Office of Emergency Operations
Washington, D.C. 20461

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PURPOSE

This report reviews the outlook for electric power supply and demand in the United States for the decade 1981-1990, from the perspective of reliability and adequacy of service.

REPORT ORGANIZATION

This report has been prepared by the Utility Systems and Emergency Communications Division of the Office of Emergency Operations. In the report the term "Staff" refers to the personnel of the Division.

Chapters I through XI deal generally with electric power supply adequacy as projected for the nine Regional Reliability Council areas of the contiguous United States. Chapter XII summarizes interruptible load data reported by the Councils. Chapter XIII is a brief discussion of cogeneration. Chapter XIV deals in detail with each of the 27 Electric Regions (sub-areas of the nine Council areas) in the contiguous U.S. The boundaries of the Regions are shown on the map on the inside back cover of this report and in the maps of Chapter I.

A glossary of terms used in the report follows Chapter XIV, and is followed by several appendices. Appendix A describes very briefly the Council structure, and includes a copy of the ERA-411 Manual, which contains all the items to which the Councils were asked to respond. Appendix A also includes a copy of the letter addressed to the President of the National Electric Reliability Council requesting the Councils to furnish data on cogeneration. Appendix B lists the utilities for which data is included in the report. Appendix C is the Staff Report, Estimated Electric Demand and Supply for Summer 1981, Contiguous United States, dated May 1981. Comments on this report are invited, and should be addressed to the Director, Office of Emergency Operations.

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APPENDIX C - Staff Report - Estimated Electric Demand and Supply for Summer 1981 - Contiguous United States. Dated May 1981. . . . C.1

GENERAL CONCLUSIONS

- The Reliability Councils project a contiguous U.S. average annual increase of 3.5% in annual energy requirements for the period 1981-1983, and an average annual increase of 3.6% for the period 1981-1990, over the actual 1980 total energy requirement of 2,293,964 gigawatthours.

- The Reliability Councils project an average annual increase of 2.7% in summer peak demand for the period 1981-1983, and an average annual increase of 3.2% for the period 1981-1990, over the actual 1980 total (non-coincidental) peak summer demand of 429,804 megawatts.

- Planned generating capacity reserve margins, computed from the peak demands and projected capacities reported by the Councils, are adequate for reliable service in most areas of the contiguous U.S. for the period 1981-1990. Margins in some Electric Regions (sub-areas of the Council areas) may, however, be insufficient over specific time intervals to assure reliable service in those Regions.

- Projected capacity reserve margins, after allowance for scheduled transfers of power and capacity unavailable for various reasons, appear adequate. But if they are reduced from the projected values by failure of nuclear and coal-based unit construction to receive necessary permits or meet completion schedules, or by unforeseen increases in peak demand, reserves could be less than adequate in some Regions. The result would be deterioration of system reliability and adequacy.

- To assure nation-wide reliable electric system operation, and reduction in the use of oil by electric utilities, current schedules for construction, licensing and commercial operation of the following nuclear units should be maintained:

  Diablo Canyon 1
  Diablo Canyon 2
  Comanche Peak
  San Onofre 2
  Summer 1
  Watts Bar 1
  Sequoyah 2
  McGuire 1 *
  Shoreham 1

  * As of June 18, 1981, this unit had a license to operate at 5% of full power.

- Coal-fired generating units whose accelerated completion would be beneficial include:

  Brandon Shores 1
  Brandon Shores 2
  Intermountain 1
  Intermountain 2
  Martin 3
  Allen 1
  Sears Island
  Seward 7
  Martin 4

- The data provided by the ERA-411 Reports show that planned reserves of generating capacity within each Reliability Council area are at or above levels that have in the past been adequate to assure reliable service. The Staff has assessed the planned reserves of the Electric Regions within each Council area by using as an indicator capability that may be unavailable during seasonal peak periods because of scheduled maintenance, forced outages or other reasons, from the reported unavailability data of the past four years. The Staff has further adjusted the capability of each Region by the net of its scheduled purchases and sales of capacity. This assessment indicates that within some of the Electric Regions there may be insufficient capacity available to satisfy projected seasonal peak demands. For these Regions, however, the generating capacity within their Council areas, in conjunction with the transmission system capacity and the usual diversity of occurrence of outages and peak demands, should be sufficient to remedy the potential deficiencies. However, since Regional reliability is a major concern, the Staff is indicating those Electric Regions that may require assistance in meeting their peak demands. These Electric Regions are listed in Tables A and B below.

Table A - Summer Peak Periods 1/
Regions With Adjusted Reserve Less Than 5%

Council	Electric Region	Years
ECAR	APS, CAPCO, CD	1982 through 1990
MAIN	CECO	1982 through 1990
	WUMS	1990
SERC	VACAR	1982 through 1990
SPP	MOKAN	1988 through 1990
WSCC	So. Cal-Nevada	1989, 1990

Table B - Winter Peak Periods 1/
Regions With Adjusted Reserve Less Than 5%

Council	Electric Region	Years
ECAR	APS, CAPCO	1982/83 through 1990/91
	AEP	1983/84; 1985/86 through 1990/91
	CD	1981/82; 1984/85 through 1990/91
MAIN	CECO	1990/91
	WUMS	1983/84; 1987/88 through 1990/91
SERC	FLORIDA	1981/82; 1982/83
	VACAR	1981/82 through 1990/91
WSCC	NWPP	1981/82 through 1986/87

1/ After adjustment of planned capability by net of scheduled purchases and sales, and for the purpose of evaluation considering generating capacity out of service based on 1977-1980 averages for scheduled maintenance, forced outages and other unavailable capacity.

o For the Electric Regions not listed in Tables A and B, the projected reserve margins appear adequate. However, unusual occurrences resulting in large scale damage to generation and transmission facilities, or delays in completion of scheduled facilities, could adversely affect the ability to supply power to loads.

CHAPTER I

Summary

1. Highlights

- o Electric power supply reliability in most areas of the United States is expected to be adequate during the period 1981-1990. Some areas may experience less reliable service than others at some time during that period, but no area is expected to face long-term unreliable service.
- o The Reliability Council projections of annual energy and peak demand requirements are less than those projected by the Councils in their April 1980 ERA-411 reports.
- o Delay in bringing new nuclear and coal-fired units into commercial operation would result in the use of oil that would otherwise not be needed. It would also increase vulnerability of electric power supply to oil supply interruptions.
- o The timely completion and licensing of certain nuclear units would improve the reliability of electric power supply in several Electric Regions and Reliability Council areas.

2. Discussion

In their April 1, 1981 Coordinated Bulk Power Supply Program reports (ERA-411), the Regional Electric Reliability Councils project lower growth rates for peak demand, energy requirements and generating capability than they projected a year earlier. Projected reserve margins, viewed in the context of historical data, appear generally adequate; specific exceptions are discussed in Section XIV.

Table I.2.1 below is a comparison of changes in power supply and demand as projected by the Reliability Councils in 1980 and 1981.

Table I.2.1
Reliability Council Projections
Contiguous U.S.

	10-Year Average Annual Percentage Increase	
	Projected in 1980 For 1979-1989	Projected in 1981 For 1980-1990
Summer Peak Demand	4.3	3.2
Winter Peak Demand	4.6	3.4
Annual Net Energy	4.2	3.5
Capability at Summer Peak	3.6	3.1
Capability at Winter Peak	3.7	3.0

The individual Council projections of annual net energy and summer peak demand are shown in Table I.2.2 below.

Table I.2.2
Projected Average Annual Percent Increase
Council Area Energy and Peak Demand

	Annual Net Energy as Projected		Summer Peak Demand as Projected	
	April 1, 1980 1979-1989	April 1, 1981 1980-1990	April 1, 1980 1979-1989	April 1, 1981 1980-1990
MAAC	3.2	2.8	2.9	1.9
NPCC	2.1	2.0	1.9	1.5
ECAR	3.8	3.6	4.0	3.3
MAIN	4.0	3.2	4.2	3.0
WSCC	4.5	4.0	4.5	3.6
SERC	4.6	3.5	4.5	3.2
MARCA	4.8	4.2	5.5	3.7
ERCOT	5.2	4.6	5.6	4.3
SPP	5.3	3.9	5.6	3.4

No change is projected from the system peak demand occurring in the summer which has become characteristic of the U.S. as a whole, although some Council areas expect to continue in a winter peaking mode. For summer 1990, the total of Council area summer peak demands 1/ is expected to be 585,932 Mw; this is 156,128 Mw more than the corresponding 1980 demand. To meet this demand, the Councils project a net dependable generating capability of 750,467 Mw. The planned reserve margins currently projected by the Councils are in general somewhat larger than those that were projected in April 1980. The annual energy requirements and the seasonal peak demands, as projected by the Councils through 1990, are shown in Tables III.1, III.2 and III.3 of Chapter III. Council projections of capability at the time of each seasonal peak period are shown in Tables IV.1 and IV.2 of Chapter IV.

Figures I.1 through I.5 following show graphically the Council projections for annual energy, seasonal peak demand and net capability extending through 1990. Figures I.6 through I.11 show the possible planned reserve margins as computed by Staff from the data in the Council reports.

1/ Non-coincident summation

3. Summary Graphs of Energy Requirements, Peak Demands, Capabilities and Planned Reserve Margins

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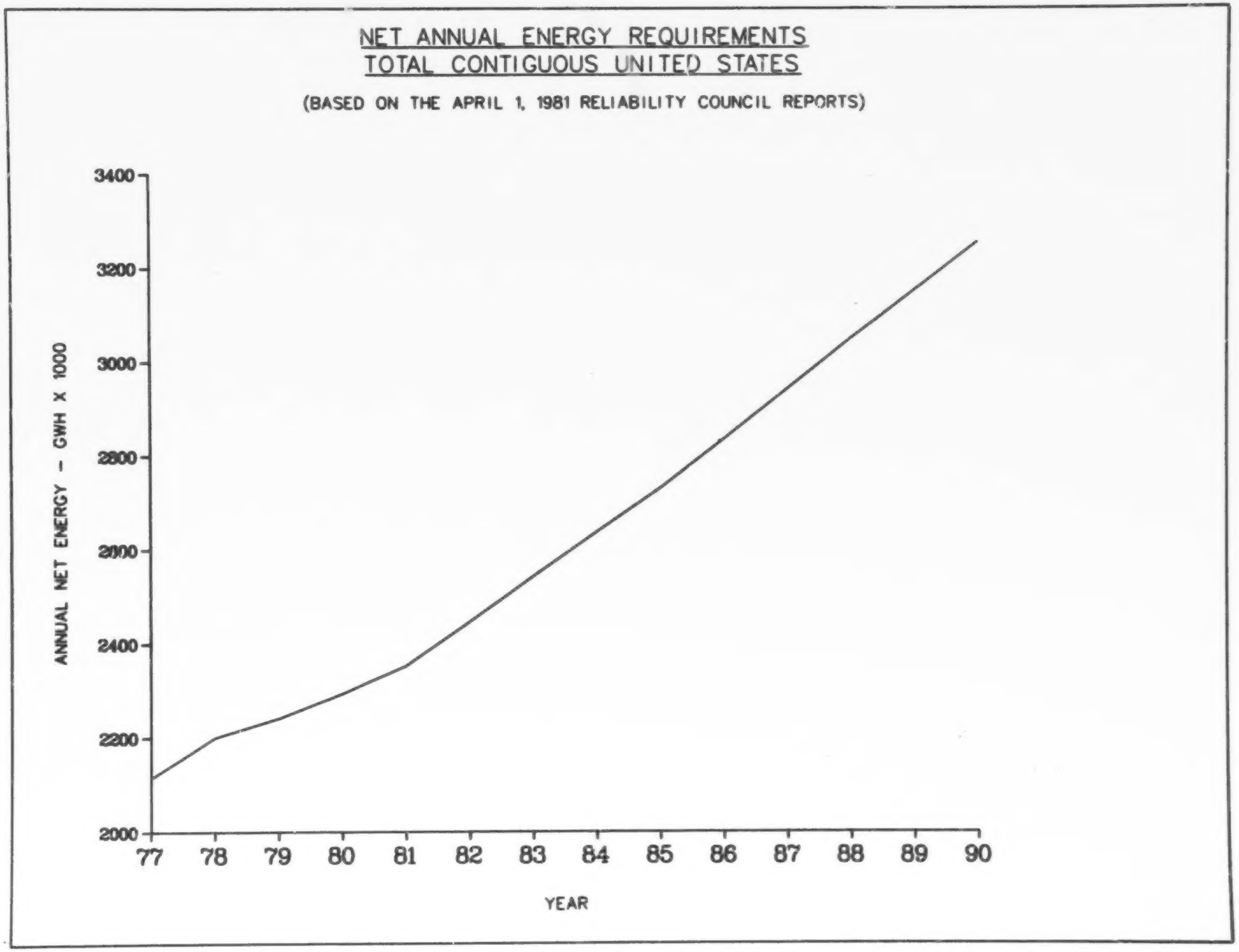

See Glossary for definitions of terms

Figure I.1

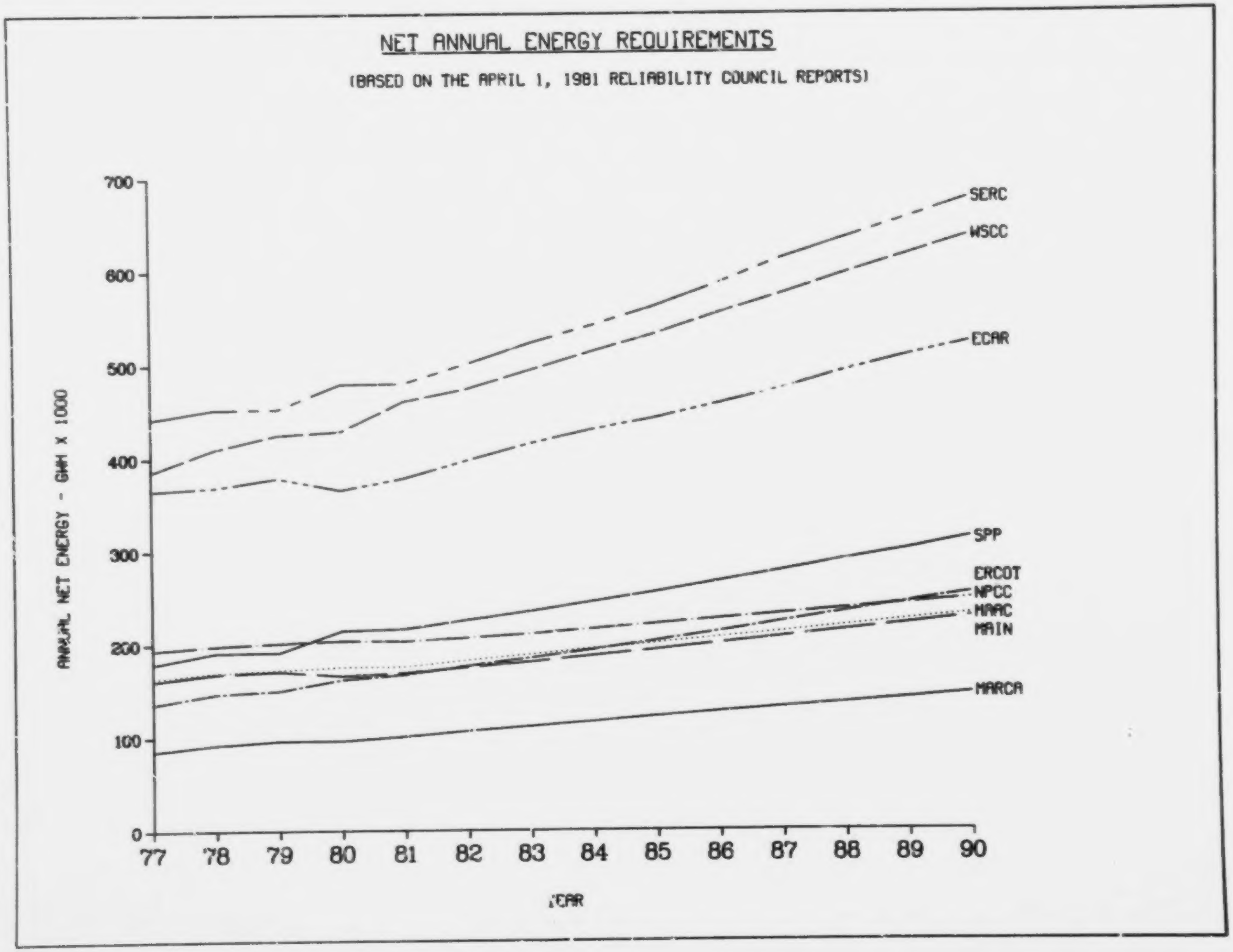

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Figure I.2

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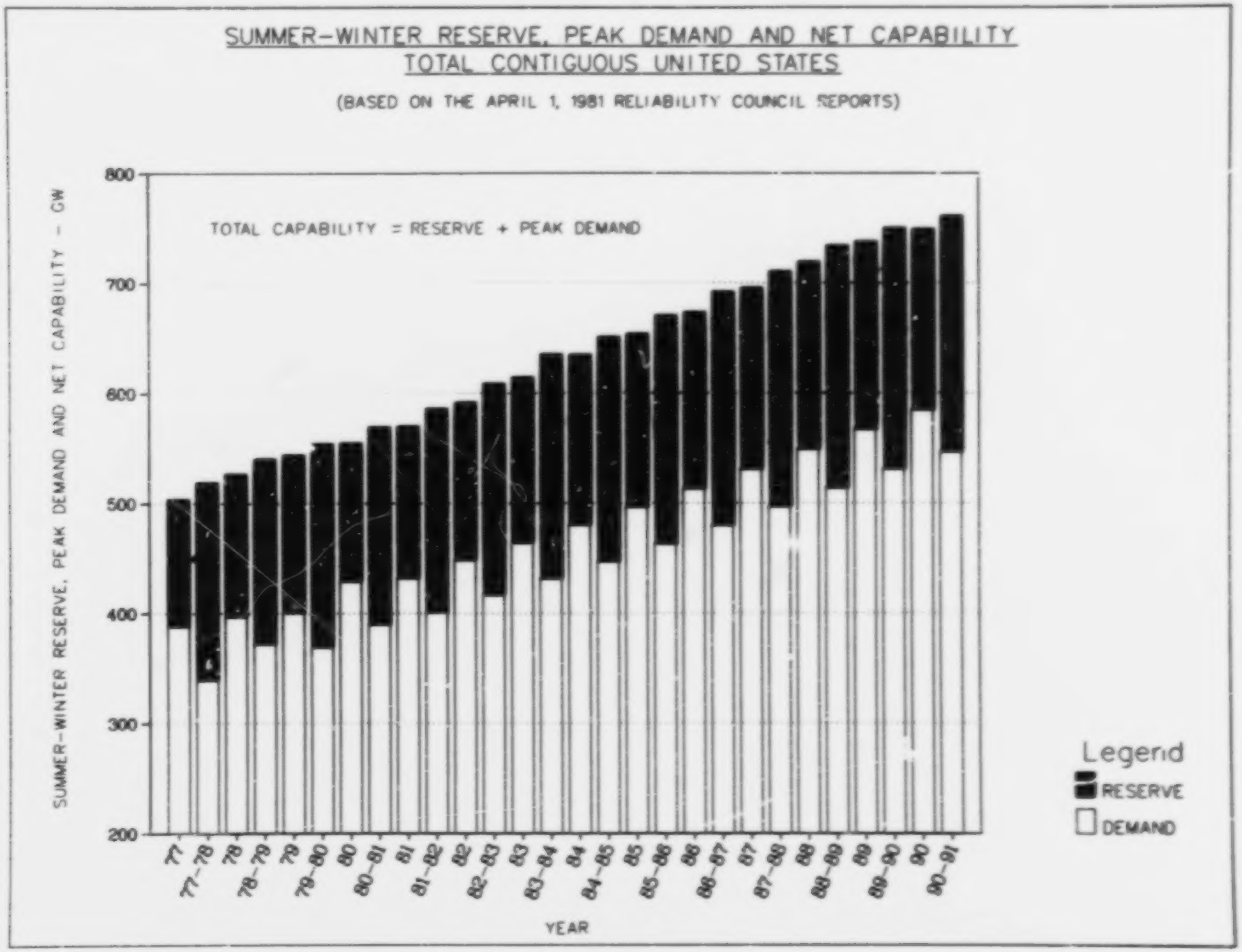
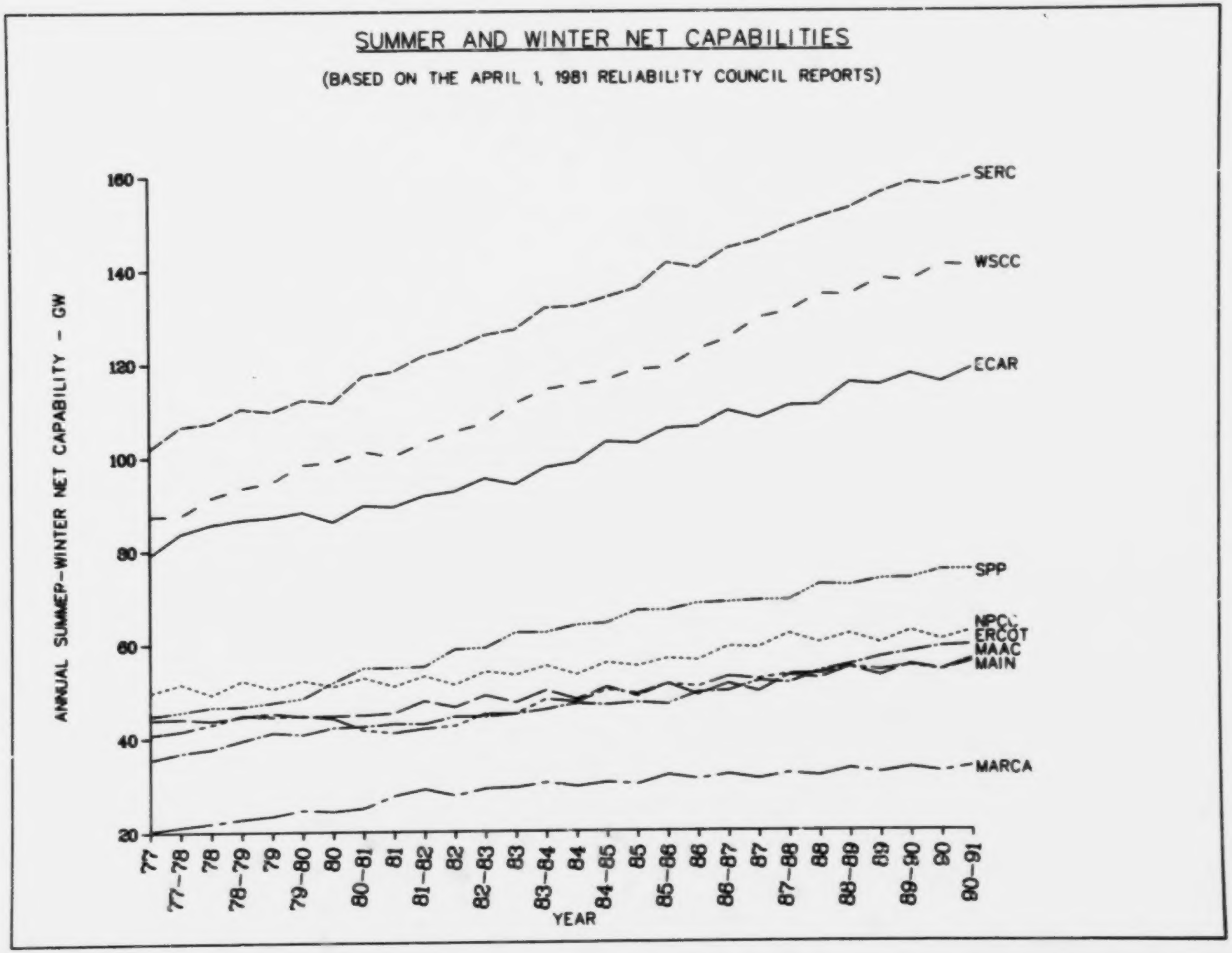

SUMMER–WINTER RESERVE, PEAK DEMAND AND NET CAPABILITY
TOTAL CONTIGUOUS UNITED STATES

(BASED ON THE APRIL 1, 1981 RELIABILITY COUNCIL REPORTS)

See Glossary for definitions of terms

Figure I.3



SUMMER AND WINTER NET CAPABILITIES

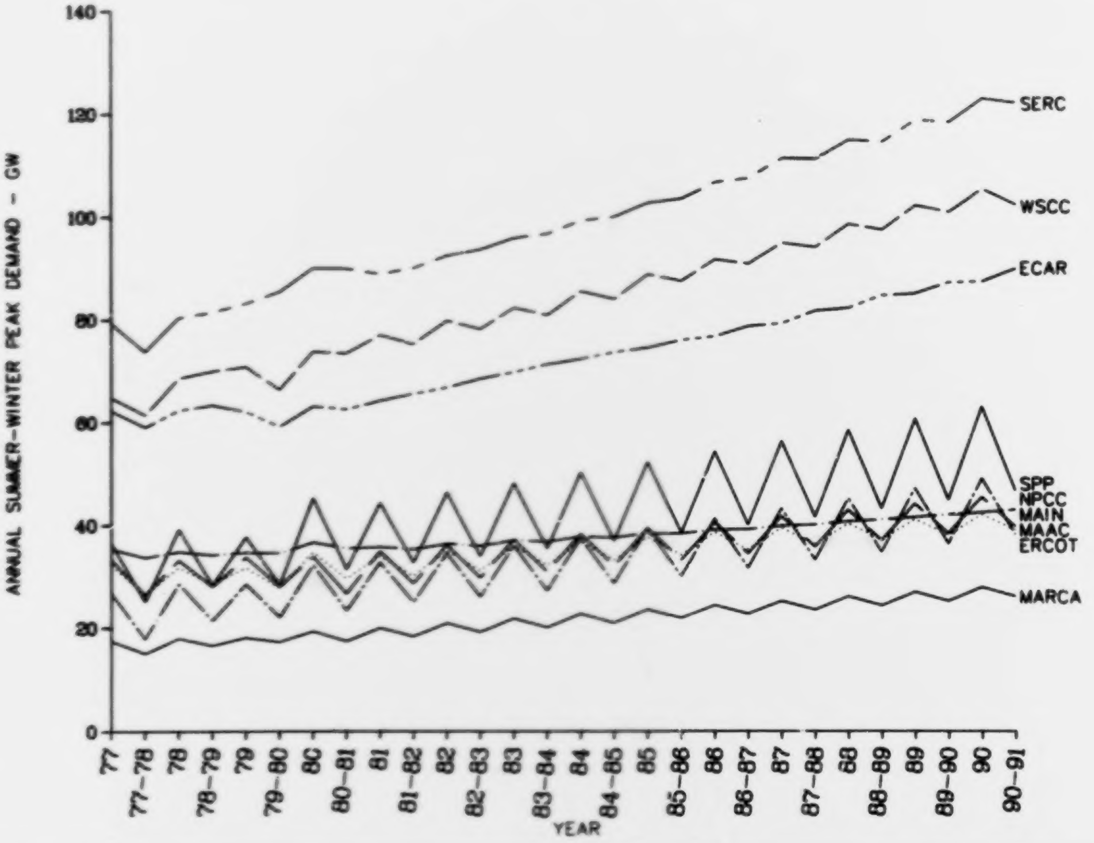
(BASED ON THE APRIL 1, 1981 RELIABILITY COUNCIL REPORTS)

See Glossary for definitions of terms

Figure I.4

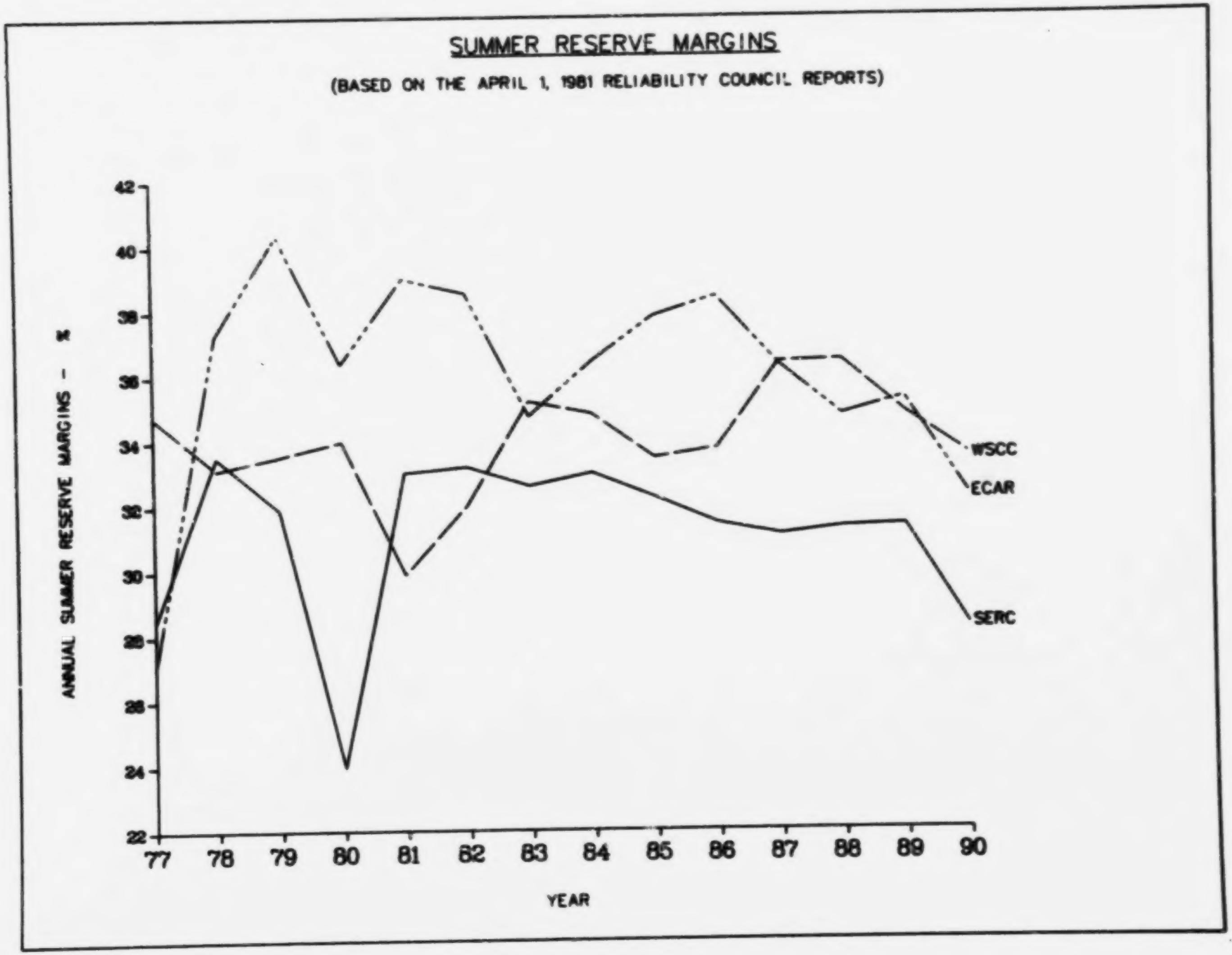
SUMMER AND WINTER PEAK DEMANDS

(BASED ON THE APRIL 1, 1981 RELIABILITY COUNCIL REPORTS)



See Glossary for definitions of terms

Figure I.5



SUMMER RESERVE MARGINS

(BASED ON THE APRIL 1, 1981 RELIABILITY COUNCIL REPORTS)

See Glossary for definitions of terms.

Figure I.6

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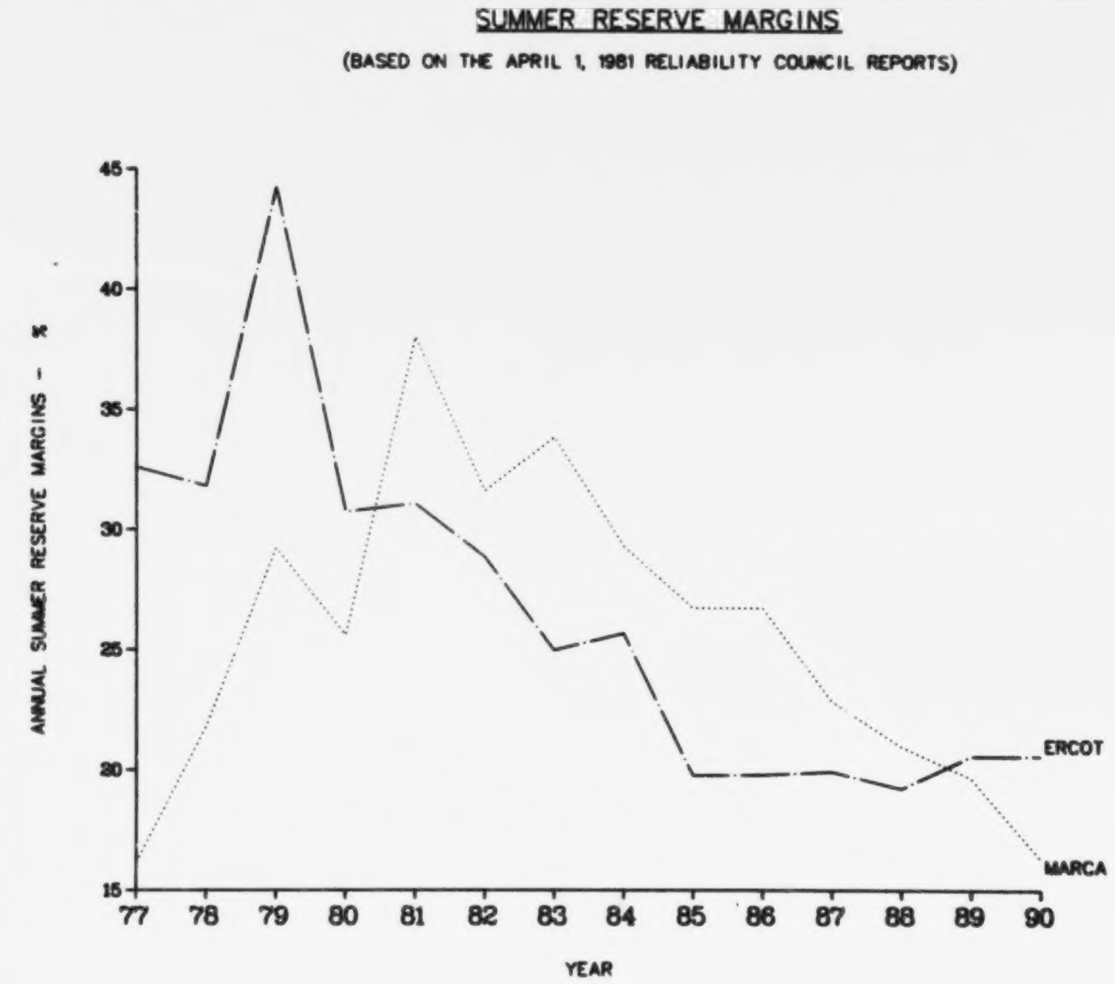

See Glossary for definitions of terms

Figure I.7

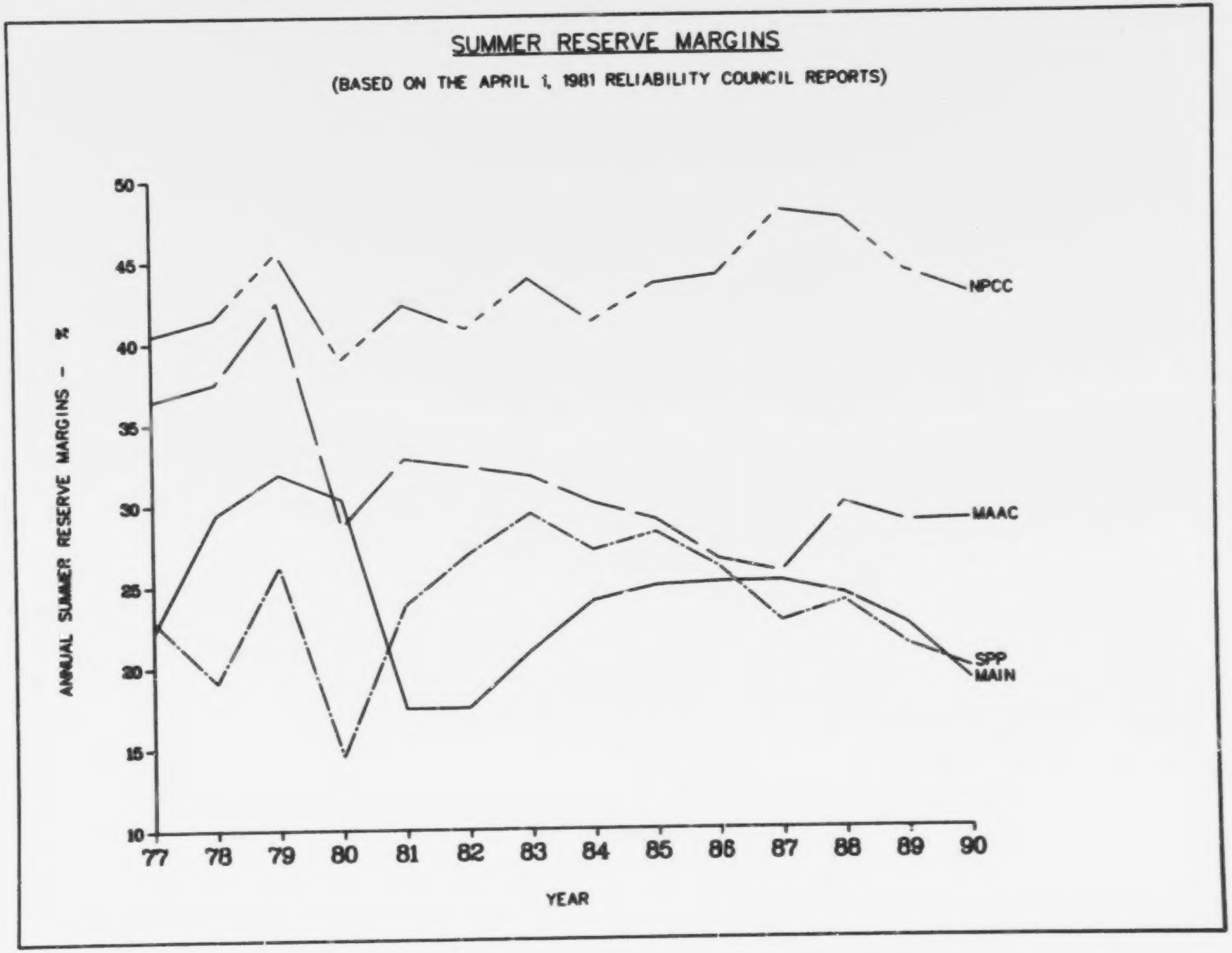

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Figure I.8

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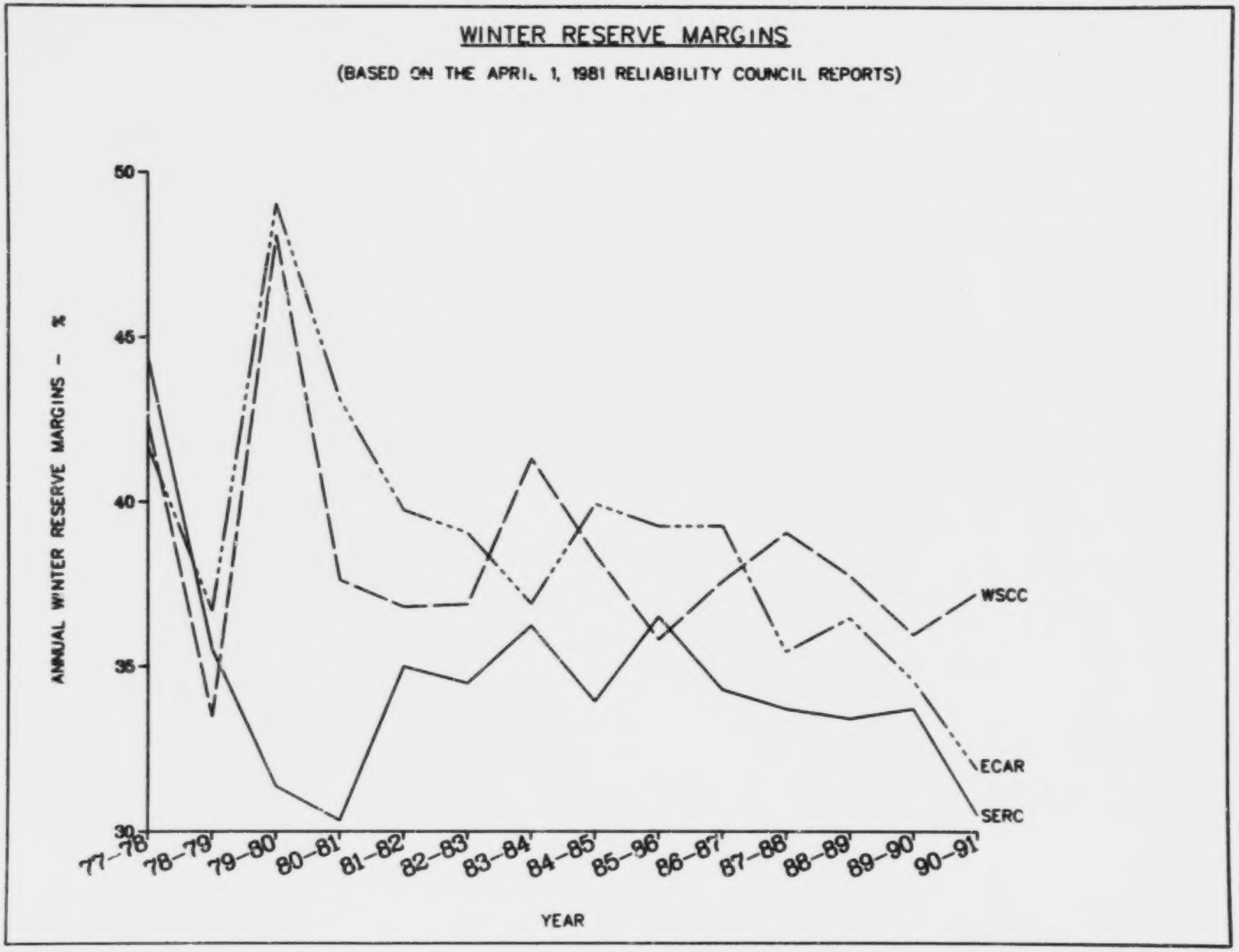
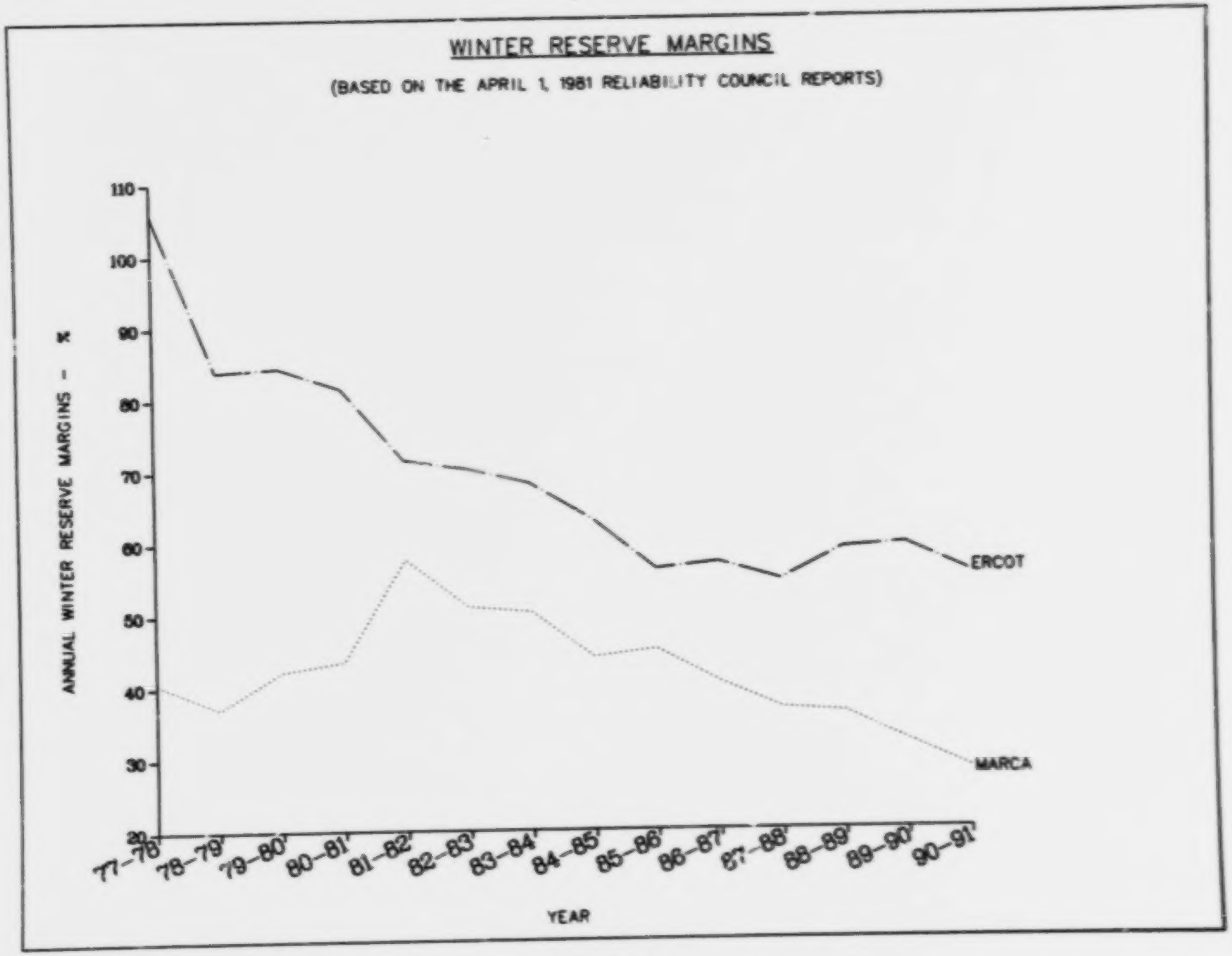


See Glossary for definitions of terms

Figure I.9



WINTER RESERVE MARGINS

(BASED ON THE APRIL 1, 1981 RELIABILITY COUNCIL REPORTS)

See Glossary for definitions of terms

Figure I.10

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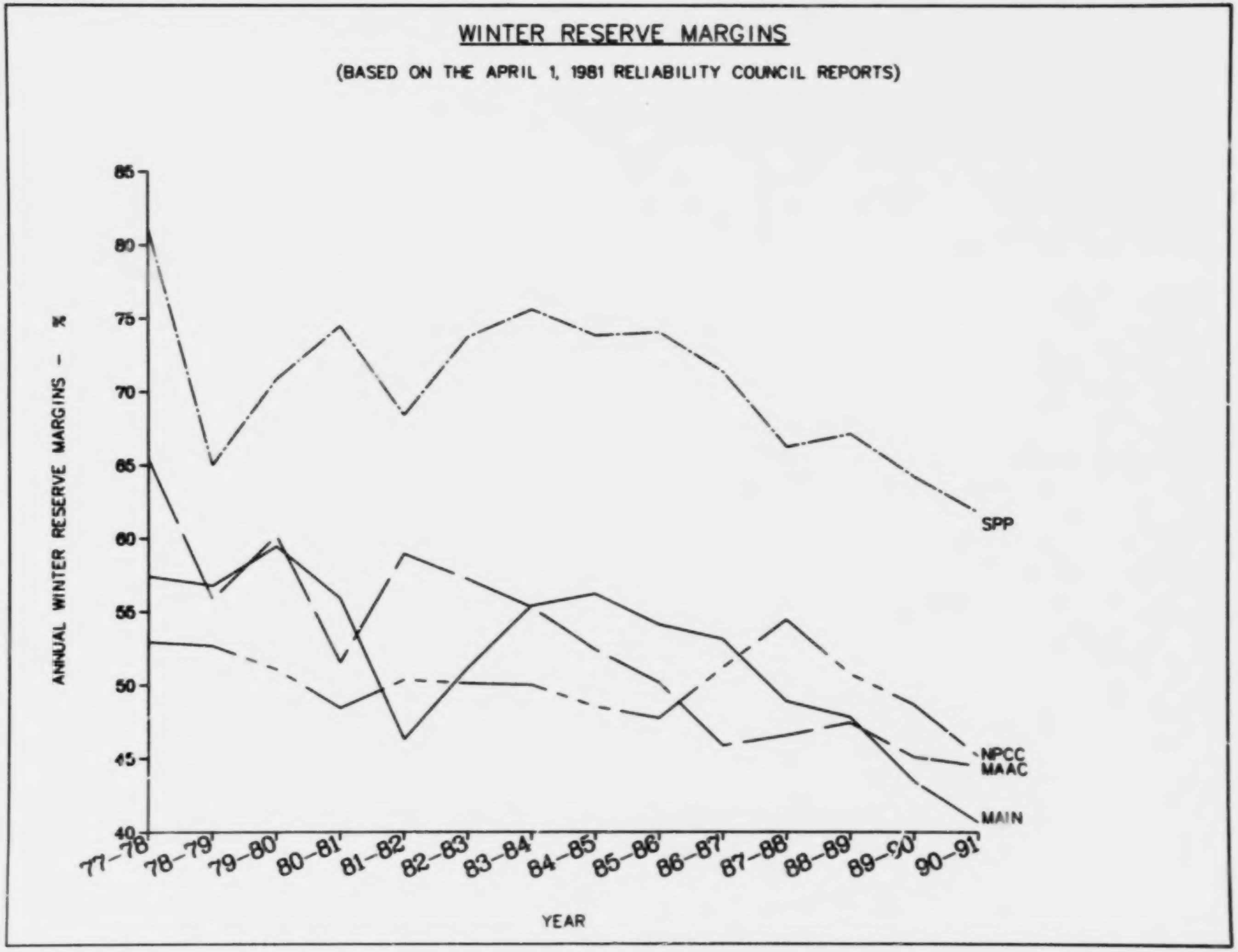

See Glossary for definitions of terms

Figure I.11

4. Maps of Electric Region and Reliability Council Boundaries

Maps of Electric Region and Reliability Council boundaries have been prepared by Staff for convenience in making regional analyses. Boundaries have been drawn on county lines wherever possible on the basis of the maps in each Council's ERA-411 Report of April 1, 1981 and the service area maps filed by utilities in their 1979 [1] Form 12 and Form 12A Reports to the Federal Energy Regulatory Commission. In order to accurately specify for analysis purposes the generating capacity and peak demands in each Electric Region and Council it is necessary to know which utilities are to be included in each group. For this purpose the list of utilities in Appendix B of this report was used. The maps and the list are intended solely as a convenience in preparation of reliability analyses. Further, for convenience, an acronym or name has been assigned to each Electric Region. The maps, the grouping in Appendix B, the acronyms and the names are not intended to specify service areas of utilities or power pools, nor to indicate control of any utility or power pool by any other utility or power pool. These items are only for convenient identification.

The Council maps furnished in the ERA-411 Reports do not show county lines, nor do many of the Form 12 maps. Therefore, the boundaries shown on the following maps were drawn using those county boundaries that appeared to be appropriate. These maps should be regarded as preliminary in nature, and may be modified. Utilities, Reliability Councils, power pools and other organizations are invited to comment upon the boundaries shown.

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[1] At the time this work was undertaken the 1980 Form 12 Reports had not yet been filed. Form 12A Reports have been discontinued by FERC.

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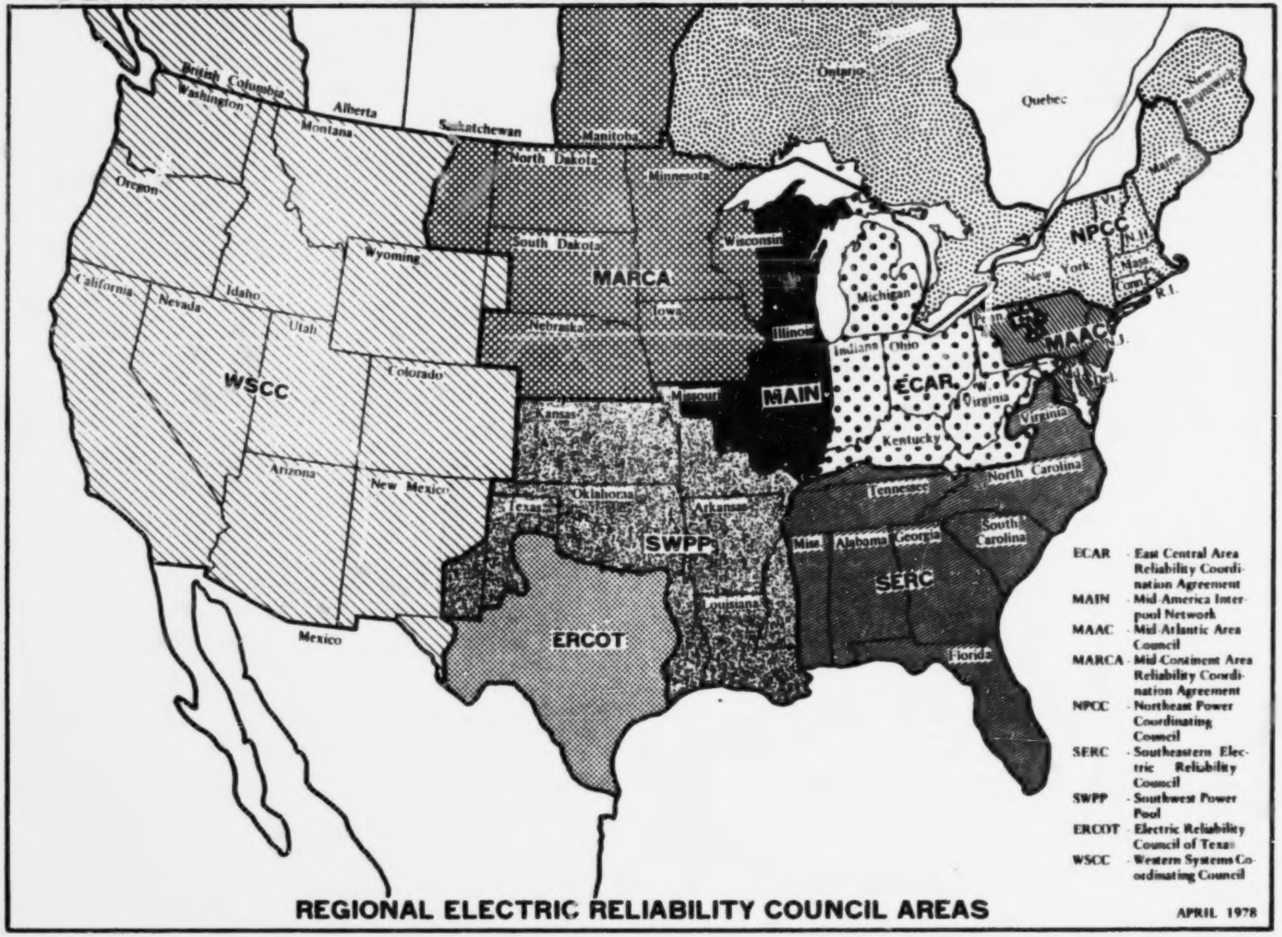
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Penn.
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Colorado
Indiana
Ohio
WSCC
Missouri
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ECAR
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Arizona
New Mexico
North Carolina
Oklahoma
Tennessee
Texas
Arkansas
SWPP
South Carolina
Miss.
Alabama
Georgia
SERC
Louisiana
Mexico
ERCOT
Florida
ECAR - East Central Area Reliability Coordination Agreement
MAIN - Mid-America Interpool Network
MAAC - Mid-Atlantic Area Council
MARCA - Mid-Continent Area Reliability Coordination Agreement
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SWPP - Southwest Power Pool
ERCOT - Electric Reliability Council of Texas
WSCC - Western Systems Coordinating Council

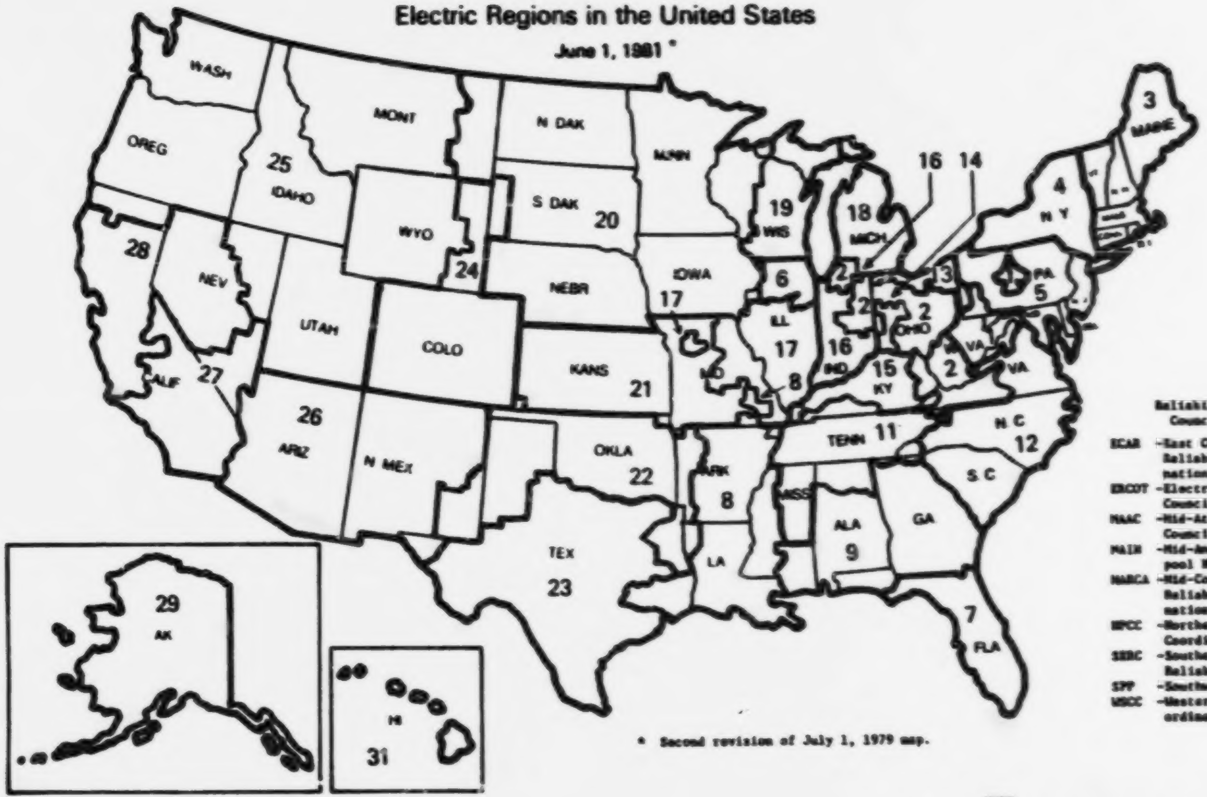
REGIONAL ELECTRIC RELIABILITY COUNCIL AREAS

APRIL 1978

Department of Energy

Electric Regions in the United States

June 1, 1981 *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Reliability Council

ECAR -East Central Area Reliability Coordination Agreement
ERCOT -Electric Reliability Council of Texas
MAAC -Mid-Atlantic Area Council
MAIN -Mid-America Interpool Network
MARCA -Mid-Continent Area Reliability Coordination Agreement
NPCC -Northeast Power Coordinating Council
SERC -Southeastern Electric Reliability Council
SPP -Southwest Power Pool
WSCC -Western Systems Coordinating Council

* Second revision of July 1, 1979 map.

Electric Region		Identification
	ECAR	
1		Allegheny Power System (APS)
2		American Electric Power System (AEP)
13		Central Area Power Coordination Group (CAPCO)
14		Cincinnati, Dayton Group (CD)
15		Kentucky Group
16		Indiana Group - All Indiana Utilities except I&M Electric Co.
18		Michigan Electric Coordinated Systems (MECS)
	ERCOT	
23		Texas Interconnected Systems Group (TIS)
	MAAC	
5		Pennsylvania-New Jersey-Maryland Interconnection (PJM)
	MAIN	
6		Commonwealth Edison Co.
17		Illinois-Missouri Group (ILLMO)
19		Wisconsin-Upper Michigan Systems Group (WUMS)
	MARCA	
20		Mid-Continent Area Power Pool (MAPP)
	NPCC	
3		New England Power Pool (NEPOOL)
4		New York Power Pool (NYPP)
	SERC	
7		Florida Coordinating Group (FCG)
9		Southern Company Group
11		Tennessee Valley Authority Group (TVA)
12		Virginia-Carolinas Group (VACAR)
	SPP	
8		Middle South Utilities/ Gulf States Utilities Group
21		Missouri-Kansas Group (MOKAN)
22		Oklahoma Group
	WSCC	
24		Rocky Mountain Power Pool (RMPP)
25		Northwest Power Pool (NWPP)
26		Arizona-New Mexico Group
27		Southern California-Nevada Group
28		Northern California-Nevada Group

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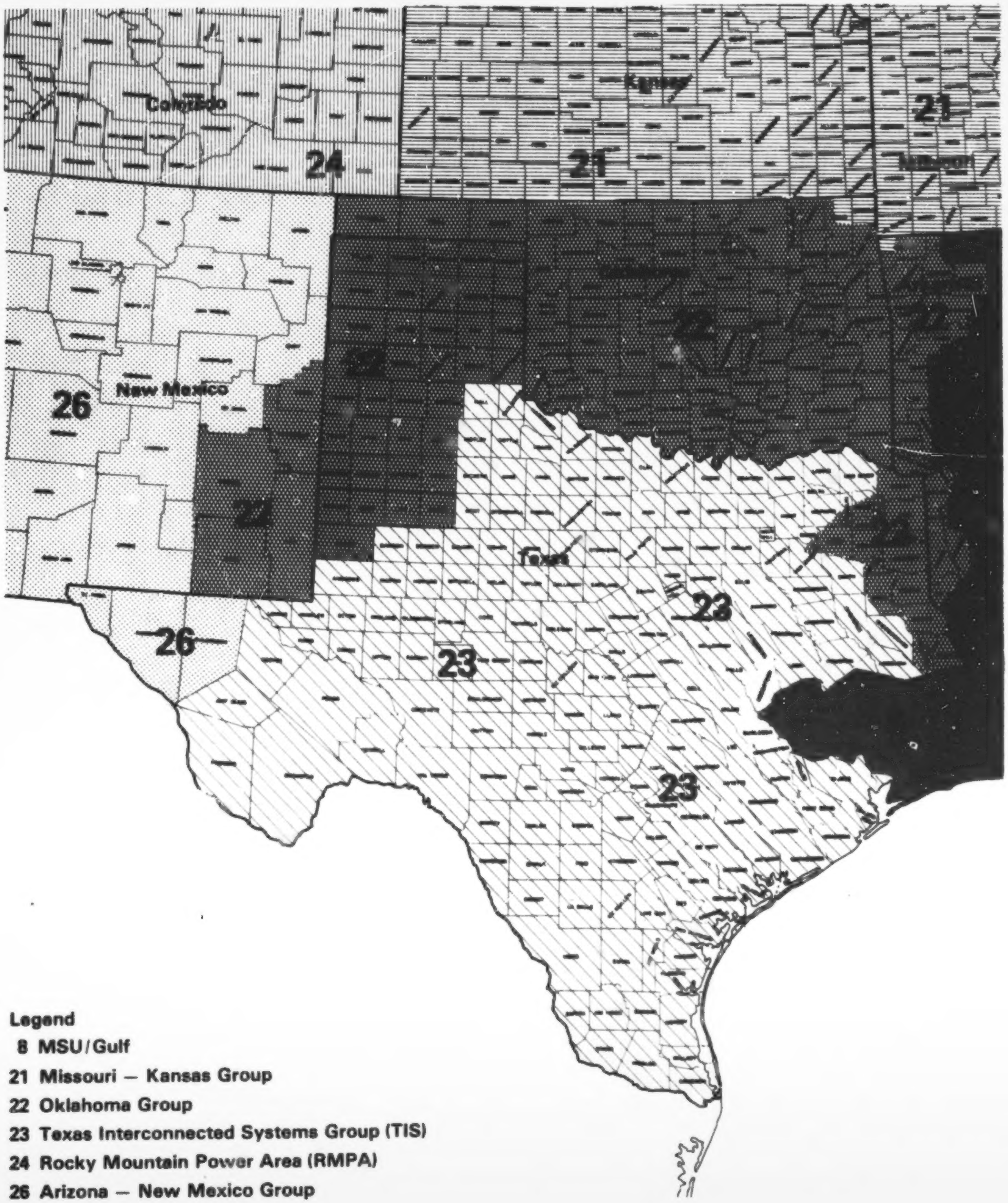
Electric Regions in the United States
June 1, 1981



Colorado
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Kansas
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Missouri
New Mexico
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Texas
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Legend
- 8 MSU/Gulf
- 21 Missouri – Kansas Group
- 22 Oklahoma Group
- 23 Texas Interconnected Systems Group (TIS)
- 24 Rocky Mountain Power Area (RMPA)
- 26 Arizona – New Mexico Group

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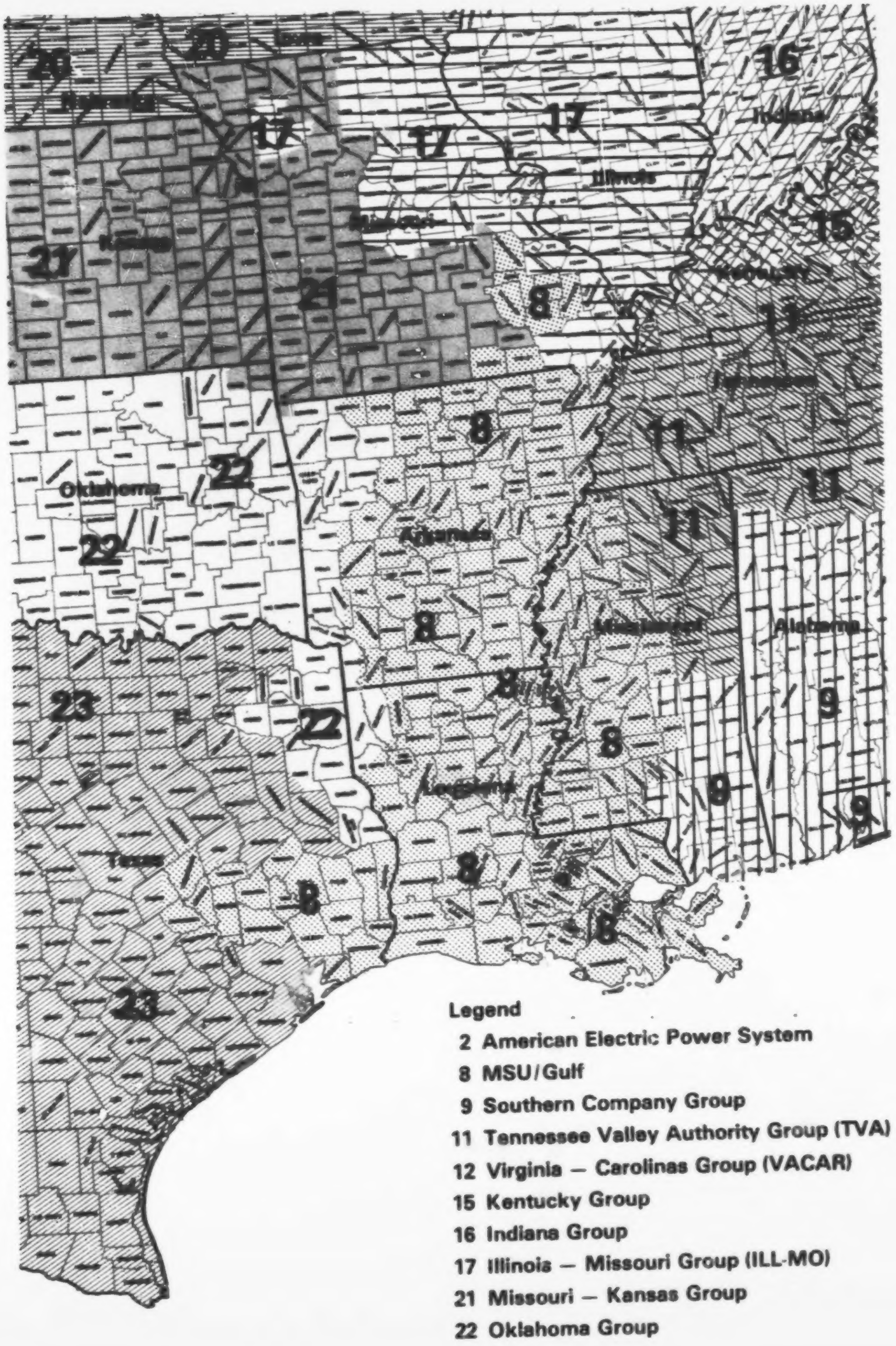
Electric Regions in the United States
June 1, 1981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Louisiana
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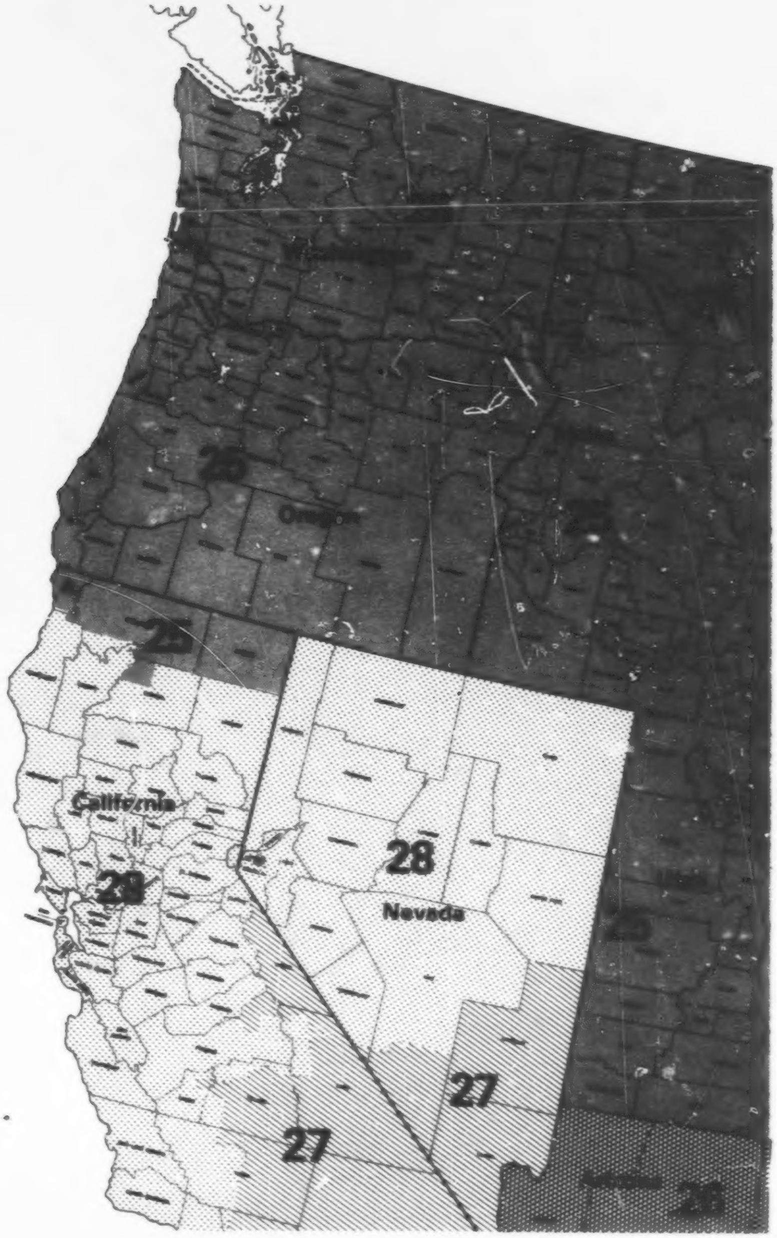
23

Legend
- 2 American Electric Power System
- 8 MSU/Gulf
- 9 Southern Company Group
- 11 Tennessee Valley Authority Group (TVA)
- 12 Virginia — Carolinas Group (VACAR)
- 15 Kentucky Group
- 16 Indiana Group
- 17 Illinois — Missouri Group (ILL-MO)
- 21 Missouri — Kansas Group
- 22 Oklahoma Group

Electric Regions in the United States
June 1, 1981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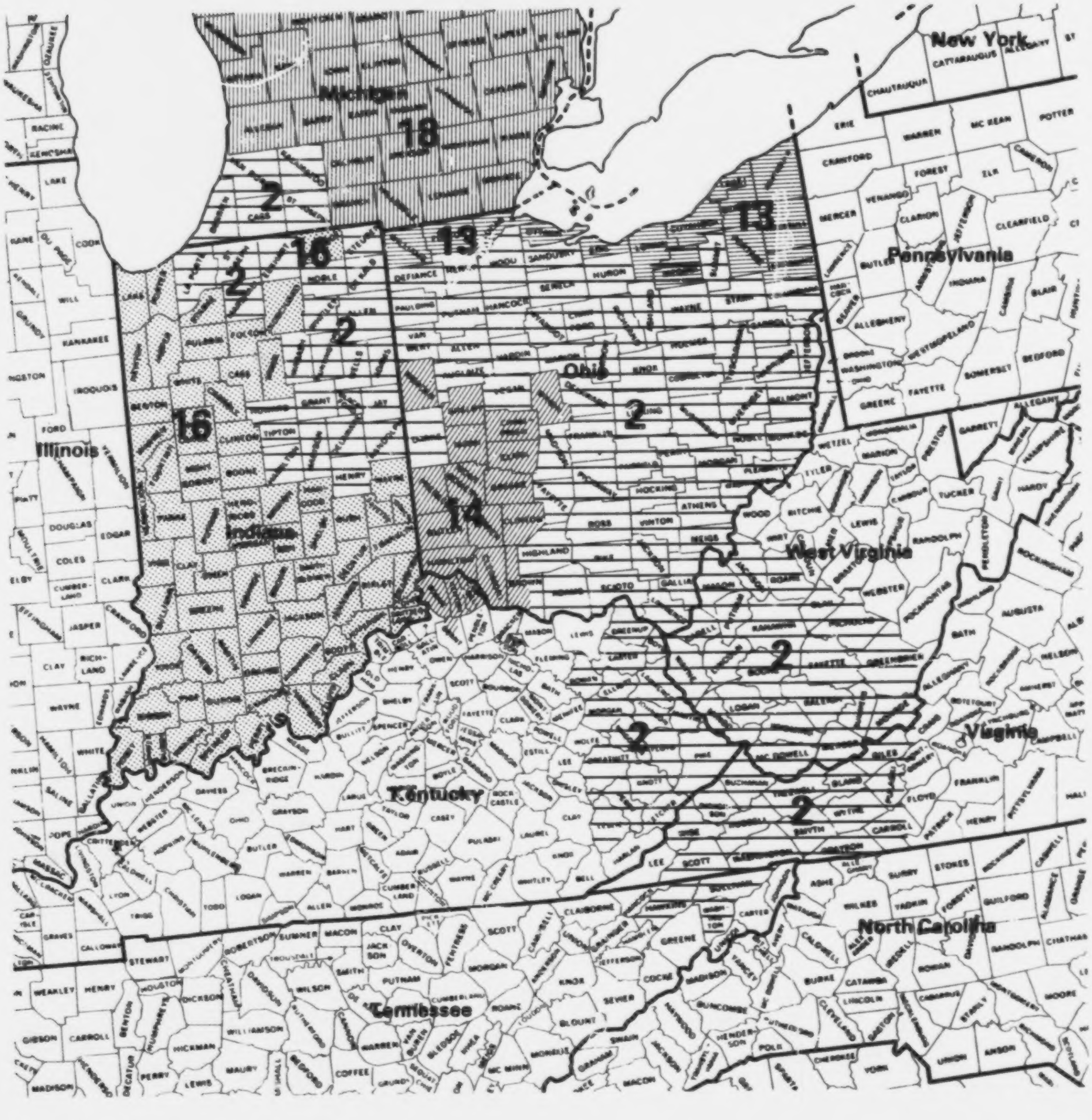
Legend

25 Northwest Power Pool (NWPP)
26 Arizona – New Mexico Group
27 Southern California – Nevada Group
28 Northern California – Nevada Group

Electric Regions in the United States
June 1, 1981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Kentucky
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North Carolina
Tennessee

Legend

- 2 American Electric Power System
- 13 Central Area Coordination Group (CAPCO)
- 14 Cincinnati – Dayton (CD)
- 16 Indiana Group
- 18 Michigan Electric Coordinated Systems (MECS)

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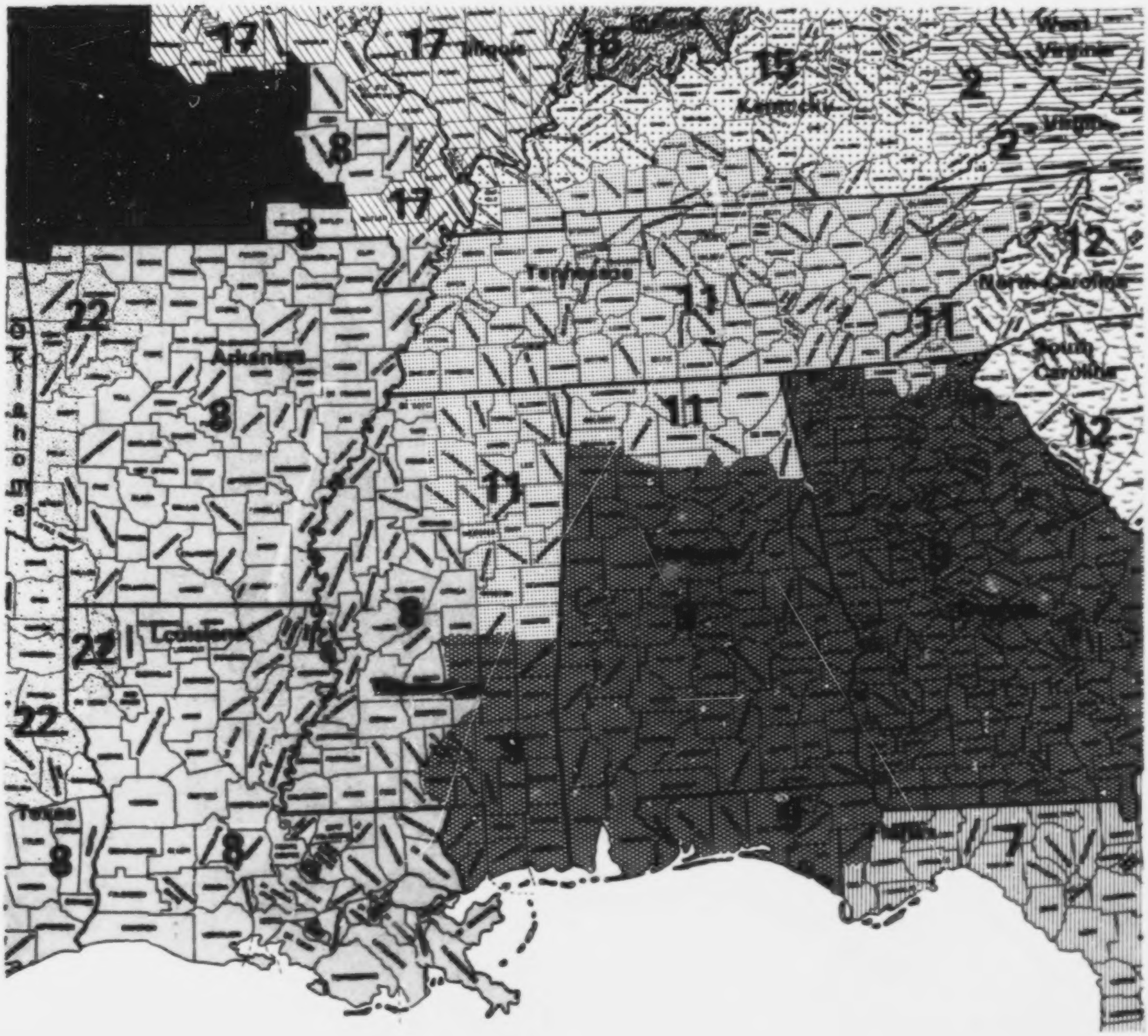
Electric Regions in the United States
June 1, 1981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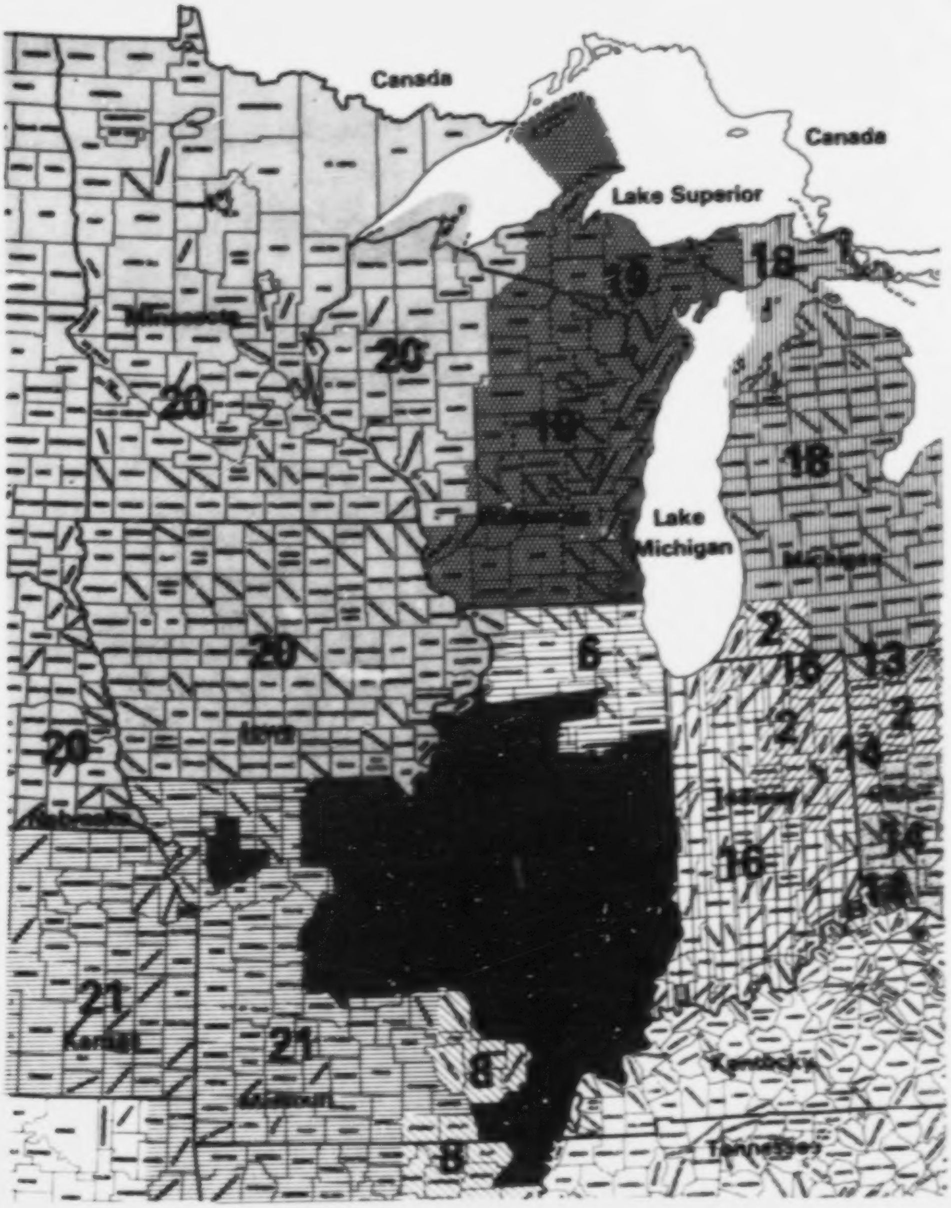
Legend

2 American Electric Power System
8 MSU/Gulf
9 Southern Company Group
11 Tennessee Valley Authority Group (TVA)
15 Kentucky Group
16 Indiana Group
17 Illinois — Missouri Group (ILL-MO)
20 Mid-Continent Area Power Pool (MAPP)
21 Missouri — Kansas Group
22 Oklahoma Group
23 Texas Interconnected Systems Group (TIS)

Electric Regions in the United States
June 1, 1981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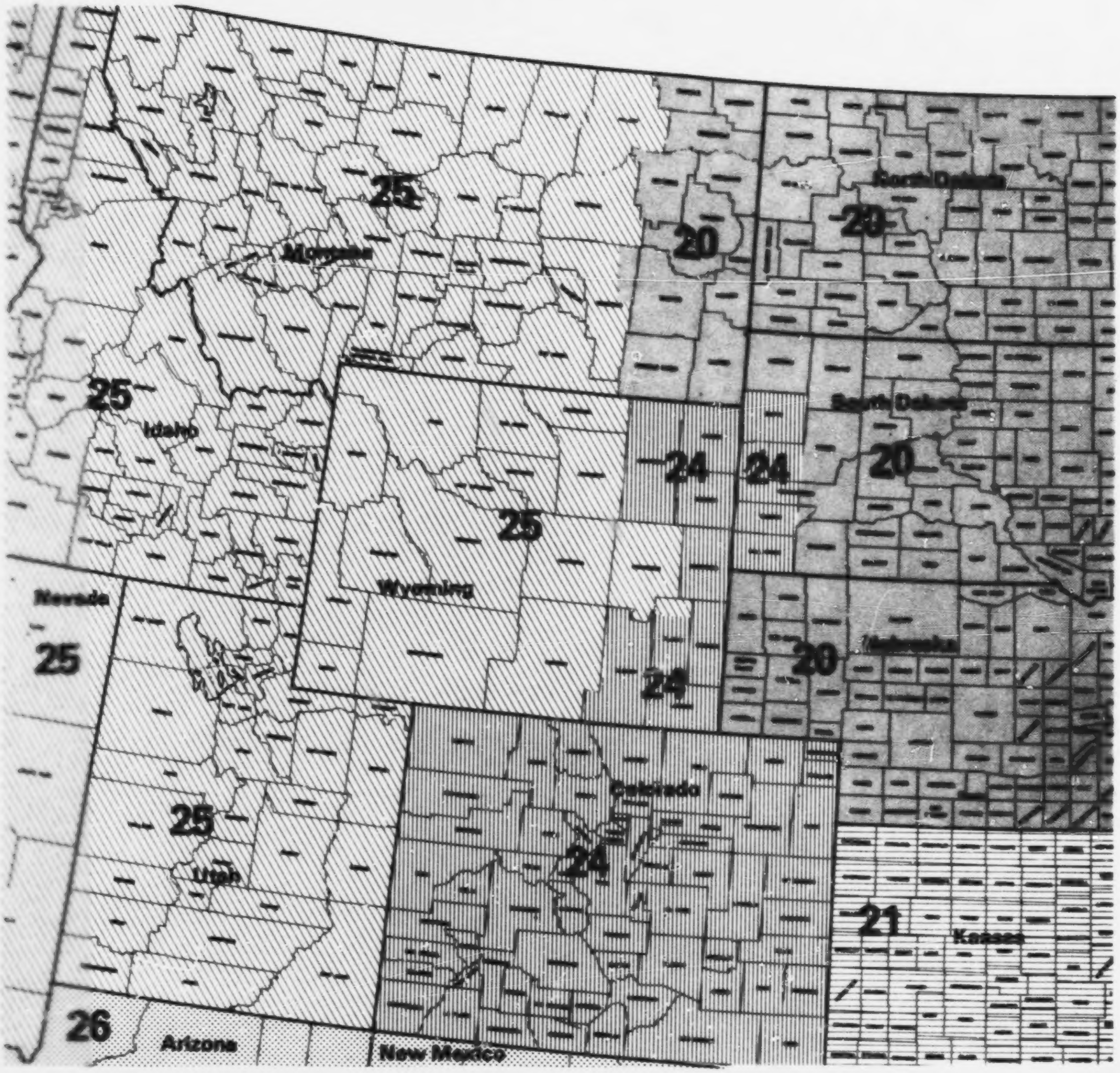
Kansas
21
Missouri
8
Kentucky
8
Tennessee

Legend

2 American Electric Power System
8 MSU/Gulf
13 Central Area Coordination Group (CAPCO)
14 Cincinnati — Dayton (CD)
16 Indiana Group
17 Illinois — Missouri Group (ILL-MO)
18 Michigan Electric Coordinated Systems (MECS)
19 Wisconsin — Upper Michigan Systems (WUMS)
20 Mid-Continent Area Power Pool (MAPP)
21 Missouri — Kansas Group

Electric Regions in the United States
June 1, 1981



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Colorado
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Utah
21
Kansas
26
Arizona
New Mexico

Legend

20 Mid-Continent Area Power Pool (MAPP)
21 Missouri-Kansas Group
24 Rocky Mountain Power Area (RMPA)
25 Northwest Power Pool (NWPP)
26 Arizona – New Mexico Group

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CHAPTER II

Introduction

This report summarizes and reviews information concerning bulk electric power supply and demand for the contiguous United States as projected for the period 1981-1990 by the nine Regional Electric Reliability Councils. The data discussed comes from the reports dated April 1, 1981 filed by the Councils with the Department of Energy (DOE) in accordance with Form ERA-411. A copy of the ERA-411 Manual containing instructions, definitions and data formats is attached in Appendix A. Also included in Appendix A is a copy of a letter from the Division of Power Supply and Reliability 1/ to the National Electric Reliability Council requesting a discussion of the impacts of cogeneration on utility planning. Other data used in this report comes from ERA-411 reports filed in earlier years, and from monthly FPC 12E-2 reports filed in the years 1977-1980.

1/ Now a part of the Utility Systems and Emergency Communications Division of DOE's Office of Emergency Operations.

[redacted]

CHAPTER III
Energy and Demand Projections

The two aspects of power requirements are demand and energy. 1/ These quantities are related, but they are not identical.

Peak Demand

Demand exists at every instant in an electric system, but what is meant by the term, as generally used, is the average of all demands in an hour. This quantity, referred to as the "average integrated one-hour demand", represents the quantity of electricity taken from the system in an hour. Every electric appliance, machine or device, when in use, presents a demand to an electric system. As the use of the device fluctuates during an hour, the instantaneous demand fluctuates. The total energy taken during any hour is called the average integrated demand of that device for that hour. The total energy taken from a system by all devices in operation during any hour is called the system average integrated demand for that hour. The demand at any instant during the hour may be greater or smaller than the average demand during the hour. For some hour of a year, the average demand will (usually) be greater than for any other hour. By definition, the demand during this hour is the annual peak demand. In the jargon of those who work with power systems, the annual peak demand may be referred to as "the annual peak", "the peak load," "the peak demand", or simply "the system peak". These terms are all intended to refer to the largest one-hour demand on a system during the course of a year.

For many systems, the hourly demands during the course of a year display a more or less regular pattern, being larger in Summer and Winter than they are in Spring and Fall. This cyclical pattern has led to the use of the terms "summer peak demand" and "winter peak demand". That is, the largest one-hour demand during the summer period is called the "summer peak demand" and the largest one-hour demand during the winter period is called the "winter peak demand". The summer period is usually defined to run from June 1 through August 31, but in some instances is extended to run through September 30. "Winter" is generally considered to be the period from December 1 of any year through the end of the following February, but may run through the end of March. It is found that for most systems in the United States, the summer peak demand and the winter peak demand are different in magnitude. A "summer-peaking system" is defined as one for which the summer peak is greater than the peak of the following winter. A "winter-peaking system" is defined as one for which the winter peak is greater than that of the following summer.

Energy and Power

Electric energy represents a quantity of electricity that has been taken from a system to do work. The work done may be manifested primarily as physical motion, or as heat, light, production of sound, transmission of radio or television signals or in some other way. Whatever the form of the ultimate use, the electricity is in the first instance obtained from some primary energy source: combustion of a fuel, nuclear fission, moving water, sunlight, chemical action or other source. The rate of use of energy, that is, the energy used per unit of time, is the "demand". Then, demand is equated to "power". But "power" is loosely used by those who discuss electric power systems; "power" may refer to demand, it may refer to "energy" or it may refer in a general way to demand and energy combined, as an output of an electric system.

1/ See Glossary for definitions of terms.

Forecasting

Adequate electric power systems require that facilities be available when needed to provide whatever demand and energy are wanted by consumers. This requirement, based on the premise that the electric system exists to serve its customers, has led to the need for "load forecasting".

The projection of what customers of an electric utility will require from the system is a basic factor in system planning. Lack of ability to store electric energy and capacity to any significant extent accentuates the critical nature of the projections. Automobiles, shoes, umbrellas or other physical articles can be produced at a rate partially divorced from the rate at which the articles are purchased, with storage facilities being used to level out fluctuations in demand and disparities between demand and production. However, aside from minor storage capacity in the form of certain types of hydroelectric facilities, there is no cushion that can be used to accommodate mismatches between the production and use of electric power. Facilities must always be available to instantaneously meet whatever demand is imposed. As a result, facilities needed to supply large rates of use of energy (peak demands) will be idle when the rate of use is low (valleys in the demand pattern). This characteristic of electric utility systems results in reserve margins that vary during the course of a year. Reserves that appear high at some period must be considered in the context of the entire system and its functioning over a long-term period. For electric power supply systems, the investment in fixed facilities is so large and the time interval between initial planning and the ultimate use of a facility is so long, that intensive effort is warranted to determine the future magnitudes and patterns of demands. This effort is described by the term "load forecasting". Forecasting is both a science and an art that deals with the future, and therefore its results are accompanied by uncertainty. The uncertainty considerations can in a forecast by the use of probability measures, confidence levels or other statistical methods that attempt to quantify the magnitude of probable error in a forecast. Table III.1 is a summary of the Reliability Council projections of net annual energy requirements for the years 1981 through 1990. The table also shows the Council actual energy requirements as reported for 1980.

Table III.2 is a summary of the Council projections of summer peak demands, and Table III.3 shows the winter peak demand projections, for 1981 through 1990. Each table also shows the actual peak demand for 1980. Because the data were compiled by the Councils early in 1981, the peak demands for winter 1980-81 are in most instances those reported as of December 31, 1980. Where the actual winter peak occurred after that date, the reported data are on the low side. The peak demands shown in Tables III.2 and III.3 are, except in the case of MAAC, non-coincidental. That is, they were obtained by summation of peak demand projections made by the individual utilities in a Council; they do not take into account the probable differences in time of occurrence of the peaks. The demands reported by MAAC represent the peaks of the entire PJM Power Pool as a unit.

TABLE III.1

ACTUAL AND PROJECTED GROWTH OF NET ANNUAL ENERGY REQUIREMENTS AS REPORTED APRIL 1, 1981 BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS 1/
CONTIGUOUS UNITED STATES

(MEGAWATT-HOURS X 1000)

	ACTUAL 1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
ECAR 2/	366093	378300	397000	414700	429500	441630	456800	472600	491500	507800	522400
MAAC	175622	175930	182822	188702	194706	200502	206241	211922	218195	224750	230713
MAIN	166173	169292	175250	180809	187253	193457	200010	206654	213540	220424	227605
MARCA 3/	96422	101052	106648	111516	116492	121850	126577	131211	135736	140516	145920
NPCC 3/	203916	203461	206841	210868	216075	221132	226258	231317	236594	241994	247267
SERC	479615	479939	500406	522167	540966	561252	585383	612020	633589	654718	676690
SPP	214816	216471	226074	235006	245218	255389	266543	277729	289760	300414	313362
SUBTOTAL	1702654	1724445	1795041	1863768	1930210	1995182	2067812	2143453	2218914	2290616	2363957
ERCOT	162327	167469	176810	185018	193683	203087	212514	222864	233263	243542	253504
WSCC 3/	428983	460805	473788	493319	513042	531653	553641	573896	595615	615901	636603
U.S. TOTAL	2293964	2352719	2445639	2542105	2636935	2729922	2833967	2943213	3047792	3150059	3254064

ANNUAL PERCENT INCREASE OVER PRECEDING YEAR

	ACTUAL 1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	AVG. INCREASE 4/ (%)
ECAR 2/	-3.41	3.33	4.94	4.46	3.57	2.82	3.44	3.46	4.00	3.32	2.88	3.62
MAAC	1.79	0.18	3.92	3.22	3.18	2.98	2.86	2.75	2.96	3.00	2.65	2.77
MAIN	-2.85	1.88	3.52	3.17	3.56	3.31	3.39	3.32	3.33	3.22	3.26	3.20
MARCA 3/	-3.10	4.80	5.54	4.56	4.46	4.60	3.88	3.66	3.45	3.52	3.85	4.23
NPCC 3/	1.09	-0.22	1.66	1.95	2.47	2.34	2.32	2.24	2.28	2.28	2.18	1.95
SERC	5.88	0.07	4.26	4.35	3.60	3.75	4.30	4.55	3.52	3.33	3.36	3.51
SPP	12.02	0.77	4.44	3.95	4.35	4.15	4.37	4.20	4.33	3.68	4.31	3.85
SUBTOTAL	2.23	1.28 5/	4.09	3.83	3.56	3.37	3.64	3.66	3.52	3.23	3.20	3.34
ERCOT	7.83	3.17	5.58	4.64	4.68	4.86	4.64	4.87	4.67	4.41	4.09	4.56
WSCC 3/	3.85	7.42	2.82	4.12	4.00	3.63	4.14	3.66	3.78	3.41	3.36	4.03
U.S. TOTAL	2.34	2.56 5/	3.95	3.94	3.73	3.53	3.81	3.75	3.65	3.36	3.30	3.56

1/ AS REPORTED IN ITEM 1 OF THE COUNCIL REPORTS. NET ENERGY IS THE ELECTRIC ENERGY REQUIRED FROM ALL SOURCES DURING THE REPORTING PERIOD TO SATISFY THE ENERGY REQUIREMENTS OF CUSTOMERS AND SUPPLY LOSSES IN THE TRANSMISSION AND DISTRIBUTION SYSTEM. IT INCLUDES THE NET ENERGY FROM INSTALLED POWER SOURCES AND ENERGY SUPPLIED BY OTHER SOURCES SUCH AS INTERCONNECTED UTILITY SYSTEMS AND INDUSTRIAL SOURCES. IT DOES NOT INCLUDE THE ENERGY REQUIRED FOR PUMPING OF PUMPED STORAGE PLANTS.

2/ TOTAL OF BULK POWER AND LIAISON SYSTEM MEMBERS.

3/ U.S. PORTION OF COUNCIL ONLY.

4/ AVERAGE OF TEN ANNUAL INCREASES FROM (1981/1980) TO (1990/1989).

5/ MAY BE SOMEWHAT MISLEADING SINCE SOME SYSTEMS EXPERIENCED SUMMER PEAKS IN 1980 THAT WERE GREATER THAN ANTICIPATED.

TABLE III.2

ACTUAL AND PROJECTED GROWTH OF SUMMER PEAK DEMANDS AS REPORTED APRIL 1, 1981 BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS 1/ CONTIGUOUS UNITED STATES

(MEGAWATTS)

	ACTUAL 1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
ECAR 2/	63255	64346	66893	69862	72388	74618	76819	79311	82335	85140	87469
MAAC	34782	34102	35162	36032	36972	37792	38692	39512	40332	41132	42012
MAIN	33915	34993	36207	37236	38298	39405	40538	41781	42968	44158	45433
MARCA 3/	19412	20039	20995	21909	22810	23626	24459	25256	26137	26986	27936
NPCC 3/	36724	35843	36443	37103	37813	38453	39163	39913	40743	41583	42433
SERC	90149	88996	92556	95944	99347	102799	106777	111459	115055	118913	123073
SPP	45334	44383	46398	48238	50317	52302	54382	56342	58534	60727	63069
SUBTOTAL	323571	322702	334654	346324	357945	368995	380830	393574	406104	418639	431419
ERCOT	32322	32825	34557	36070	37576	39547	41337	43281	45211	47207	49058
WSCC 3/	73911	77138	79884	82394	85597	88882	91817	95004	98664	102286	105455
U.S. TOTAL	429804	432665	449095	464788	481118	497424	513984	531859	549979	568132	585932

ANNUAL PERCENT INCREASE OVER PRECEDING YEAR

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	AVG. INCREASE 4/ (%)
ECAR 2/	1.73	1.72	3.96	4.44	3.62	3.08	2.95	3.24	3.81	3.41	2.74	3.30
MAAC	8.57	-1.96	3.11	2.47	2.61	2.22	2.38	2.12	2.08	1.98	2.14	1.92
MAIN	0.33	3.18	3.47	2.84	2.85	2.89	2.88	3.07	2.84	2.77	2.89	2.97
MARCA 3/	6.88	3.23	4.77	4.35	4.11	3.58	3.53	3.26	3.49	3.25	3.50	3.71
NPCC 3/	5.70	-2.40	1.67	1.81	1.91	1.69	1.85	1.91	2.08	2.06	2.04	1.46
SERC	8.27	-1.28	4.00	3.66	3.55	3.47	3.87	4.38	3.23	3.35	3.50	3.17
SPP	20.18	-2.10	4.54	3.97	4.31	3.94	3.98	3.60	3.89	3.75	3.86	3.37
SUBTOTAL	7.17	-0.27 5/	3.70	3.49	3.36	3.09	3.21	3.35	3.18	3.09	3.05	2.92
ERCOT	13.19	1.56	5.28	4.38	4.18	5.25	4.53	4.70	4.46	4.41	3.92	4.27
WSCC 3/	4.18	4.37	3.56	3.14	3.89	3.84	3.30	3.47	3.85	3.67	3.10	3.62
U.S. TOTAL	7.07	0.67 5/	3.80	3.49	3.51	3.39	3.33	3.48	3.41	3.30	3.13	3.15

1/ AS REPORTED IN ITEM 1 OF THE COUNCIL REPORTS. THE PEAK DEMANDS OF THE COUNCILS ARE NOT NECESSARILY COINCIDENT IN TIME. THE ACTUAL 7-COUNCIL SUBTOTALS AND THE U.S. TOTALS WILL BE LESS THAN THE TOTALS SHOWN HERE BECAUSE THE COUNCIL PEAKS OCCUR AT DIFFERENT TIMES. THE TOTALS ARE SHOWN ONLY TO INDICATE THE APPROXIMATE LEVEL OF 7-COUNCIL AND NATIONAL PEAK POWER USE. THE DEMANDS INCLUDE INTERRUPTIBLE LOADS AND EXCLUDE INTERREGIONAL PURCHASES AND SALES. THE COUNCIL DESIGNATION IS "PEAK HOUR DEMAND".

2/ TOTAL OF BULK POWER AND LIAISON SYSTEM MEMBERS.

3/ U.S. PORTION OF COUNCIL ONLY.

4/ AVERAGE OF TEN ANNUAL INCREASES FROM (1981/1980) TO (1990/1989).

5/ MAY BE SOMEWHAT MISLEADING SINCE SOME SYSTEMS EXPERIENCED SUMMER PEAKS IN 1980 THAT WERE GREATER THAN ANTICIPATED.

TABLE III.3

ACTUAL AND PROJECTED GROWTH OF WINTER PEAK DEMANDS AS REPORTED APRIL 1, 1981 BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS 1/ CONTIGUOUS UNITED STATES

(MEGAWATTS)

	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
ECAR 2/	62673	65671	68630	71393	73758	76087	78784	81779	84793	87314	89984
MAAC	29625*	30112	31182	32222	33242	34212	35162	36232	37162	38132	39092
MAIN	26715	28699	29831	30988	32096	33280	34487	35798	37067	38401	39720
MARCA 3/	17447	18424	19281	20166	21075	21972	22757	23546	24358	25245	26168
NPCC 3/	35580*	35383	36063	36873	37663	38423	39213	40133	41073	42063	43043
SERC	90069*	90159	93737	96792	100096	103581	107567	111307	114682	118526	122268
SPP	31496	32781	34054	35561	37052	38548	40126	41633	43276	44943	46739
SUBTOTAL	293605	301229	312778	323995	334982	346103	358096	370428	382411	394624	407014
ERCOT	23414	25065	26153	27340	28759	30104	31719	33289	34816	36409	38233
WSCC 3/	73583	75356	78279	80983	84097	87595	90956	94170	97559	101015	102446
U.S. TOTAL	390599	401650	417210	432318	447838	463802	480771	497887	514786	532048	547693

ANNUAL PERCENT INCREASE OVER PRECEDING YEAR

	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91	AVG. INCREASE 4/ (%)
ECAR 2/	5.75	4.78	4.51	4.03	3.31	3.16	3.54	3.80	3.69	2.97	3.06	3.68
MAAC	5.37	1.64	3.55	3.34	3.17	2.92	2.78	3.04	2.57	2.61	2.52	2.81
MAIN	-4.94	7.43	3.94	3.88	3.58	3.69	3.63	3.80	3.54	3.60	3.43	4.05
MARCA 3/	0.61	5.60	4.65	4.59	4.51	4.26	3.57	3.47	3.45	3.64	3.66	4.14
NPCC 3/	2.77	-0.55	1.92	2.25	2.14	2.02	2.06	2.35	2.34	2.41	2.33	1.93
SERC	5.31	0.10	3.97	3.26	3.41	3.48	3.85	3.48	3.03	3.35	3.16	3.11
SPP	10.89	4.08	3.88	4.43	4.19	4.04	4.09	3.76	3.95	3.85	4.00	4.03
SUBTOTAL	4.35	2.60	3.83	3.59	3.39	3.32	3.47	3.44	3.23	3.19	3.14	3.32
ERCOT	5.85	7.05	4.34	4.54	5.19	4.68	5.36	4.95	4.59	4.58	5.01	5.03
WSCC 3/	10.65	2.41	3.88	3.45	3.85	4.16	3.84	3.53	3.60	3.54	1.42	3.37
U.S. TOTAL	5.57	2.83	3.87	3.62	3.59	3.56	3.66	3.56	3.39	3.35	2.94	3.44

1/ AS REPORTED IN ITEM 1 OF THE COUNCIL REPORTS. THE PEAK DEMANDS OF THE COUNCILS ARE NOT NECESSARILY COINCIDENT IN TIME. THE ACTUAL 7-COUNCIL SUBTOTALS AND THE U.S. TOTALS WILL BE LESS THAN THE TOTALS SHOWN HERE BECAUSE THE COUNCIL PEAKS OCCUR AT DIFFERENT TIMES. THE TOTALS ARE SHOWN ONLY TO INDICATE THE APPROXIMATE LEVEL OF 7-COUNCIL AND NATIONAL PEAK POWER USE. THE DEMANDS INCLUDE INTERRUPTIBLE LOADS AND EXCLUDE INTERREGIONAL PURCHASES AND SALES. THE COUNCIL DESIGNATION IS "PEAK HOUR DEMAND".

2/ TOTAL OF BULK POWER AND LIAISON SYSTEM MEMBERS.

3/ U.S. PORTION OF COUNCIL ONLY.

4/ AVERAGE OF TEN ANNUAL INCREASES FROM (1981-82/1980-81) TO (1990-91/1989-90).

* INDICATES ACTUAL PEAK DEMANDS FROM ERA-119M REPORTS FOR JANUARY 1981.

CHAPTER IV
GENERATING CAPACITY PROJECTIONS

The generating capacity planned by the Regional Councils for meeting the seasonal peak demands through 1990 is shown in Table IV.1 (Summer) and Table IV.2 (Winter). These tables also show the generating capability that was reported in Form FPC 12E-2 for the time of the summer 1980 and December 1980 peak demands.

TABLE IV.1

ACTUAL AND PROJECTED GROWTH OF SUMMER NET DEPENDABLE CAPABILITIES AS REPORTED APRIL 1, 1981 BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS 1/ CONTIGUOUS UNITED STATES

(MEGAWATTS)

	* 1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
ECAR 2/	86267	89435	92669	94124	98736	102824	106322	108102	110949	115168	115745
MAAC 5/	44752	45296	46528	47472	48091	48761	48962	49679	52421	52976	54156
MAIN	44214	41106	42539	45048	47504	49234	50724	52301	53441	54084	54084
MARCA 3/	24384	27659	27633	29327	29499	29946	30999	31029	31618	32292	32483
NPCC 3/	51032	51007	51326	53384	53400	55201	56415	59066	60090	59981	60626
SERC	111754	118380	123275	127223	132123	135931	140336	146094	151051	156196	157868
SPP	51932	54950	58888	62435	63980	67064	68559	69124	72538	73613	75532
SUBTOTAL	414335	427833	442858	459013	473333	488961	502317	515395	532108	544310	550494
ERCOT	42263	43031	44536	45084	47231	47366	49518	51904	53902	56912	59147
WSCC 3/	99036	100196	105497	111384	115394	118613	122793	129562	134610	137915	140826
U.S. TOTAL	555631	571063	592841	615481	625958	654940	674628	696861	720620	739137	750467

ANNUAL PERCENT INCREASE OVER PRECEDING YEAR

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	AVG. INCREASE 4/ (%)
ECAR 2/	-1.13	3.67	3.62	1.57	4.90	4.14	3.40	1.67	2.63	3.80	0.50	2.99
MAAC	-1.18	1.22	2.72	2.03	1.30	1.39	0.41	1.46	5.52	1.06	2.23	1.93
MAIN	-3.86	-7.03	3.49	5.90	5.45	3.64	3.03	3.11	2.18	1.20	0.0	2.10
MARCA 3/	3.89	13.43	-0.09	6.13	0.59	1.52	3.52	0.10	1.90	2.13	0.59	2.98
NPCC 3/	0.89	-3.05	0.63	4.01	0.03	3.37	2.20	4.70	1.73	-0.18	1.08	1.75
SERC	1.77	5.93	4.13	3.20	3.85	2.88	3.24	4.10	3.39	3.41	1.07	3.52
SPP	9.05	5.81	7.17	6.02	2.47	4.82	2.23	0.82	4.94	1.48	2.61	3.84
SUBTOTAL	1.40	3.26	3.51	3.65	3.12	3.30	2.73	2.60	3.24	2.29	1.14	2.88
ERCOT	2.59	1.82	3.50	1.23	4.76	0.29	4.54	4.82	3.85	5.58	3.93	3.43
WSCC 3/	4.53	1.17	5.29	5.63	3.60	2.79	3.52	5.51	3.90	2.46	2.11	3.59
U.S. TOTAL	2.03	2.78	3.81	3.82	3.33	2.98	3.01	3.30	3.41	2.57	1.53	3.05

1/ AS REPORTED IN ITEM 3-A OF THE COUNCIL REPORTS. NET DEPENDABLE CAPABILITY IS THE STEADY HOURLY OUTPUT WHICH GENERATING EQUIPMENT IS EXPECTED TO SUPPLY TO SYSTEM LOAD, EXCLUSIVE OF AUXILIARY POWER. FOR THE PURPOSES OF THIS TABLE "NET DEPENDABLE CAPABILITY" INCLUDES PUMPED STORAGE UNITS AND OTHER SOURCES WHICH MAY HAVE ENERGY SUPPLY LIMITATION, BUT WHICH ARE EXPECTED TO BE AVAILABLE DURING THE PEAK DEMAND PERIOD.

2/ TOTAL OF BULK POWER AND LIAISON SYSTEM MEMBERS.

3/ U.S. PORTION OF COUNCIL ONLY.

4/ AVERAGE OF TEN ANNUAL INCREASES FROM (1981/1980) TO (1990/1989).

5/ DOE STAFF HAS MODIFIED THE DATA REPORTED BY MAAC BY ASSUMING THAT TMI 2 WILL BE OUT OF SERVICE FOR THE SUMMERS OF 1981-1987.

* CAPABILITIES IN THIS COLUMN ARE FROM ERA-119M REPORTS FOR SUMMER 1980.

TABLE IV.2

ACTUAL AND PROJECTED GROWTH OF WINTER NET DEPENDABLE CAPABILITIES AS REPORTED APRIL 1, 1981 BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS 1/
CONTIGUOUS UNITED STATES

(MEGAWATTS)

	* 1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
ECAR 2/	89683	91775	95440	97745	103218	105959	109722	110770	115720	117505	118671
NAAC 5/	44900	47865	49029	50048	50672	51377	51296	53105	54793	55328	56486
MAIN	41653	41993	45098	48163	50143	51295	52815	53304	54794	55089	55884
NARCA 3/	25044	29061	29131	30322	30351	31863	31962	32193	33157	33356	33566
NPCC 3/	52820	53208	54140	55319	55949	56770	59285	61989	61926	62535	62494
SERC	117396	121719	126071	131868	134067	141397	144462	148827	153004	158498	159567
SPP	54957	55210	59165	62444	64411	67093	68755	69216	72328	73806	75621
SUBTOTAL	426453	440831	458074	475909	488811	505754	518297	529404	545722	556117	562289
ERCOT	42492	42986	44514	45981	46894	47006	49804	51439	55312	58047	59467
WSCC 3/	101267	103096	107157	114436	116389	118969	125146	130965	134400	137350	140600
U.S. TOTAL	570212	586913	609745	636326	652094	671729	693247	711808	735434	751514	762356

ANNUAL PERCENT INCREASE OVER PRECEDING YEAR

	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91	AVG. INCREASE 4/ (%)
ECAR 2/	1.54	2.33	3.99	2.42	5.60	2.66	3.55	0.96	4.47	1.54	0.99	2.85
NAAC	0.60	6.60	2.43	2.08	1.25	1.39	-0.16	3.53	3.18	0.98	2.09	2.34
MAIN	-7.86	0.82	7.39	6.80	4.11	2.30	2.96	0.93	2.80	0.54	1.44	3.01
NARCA 3/	1.57	16.04	0.24	4.09	0.10	4.98	0.31	0.72	2.99	0.60	0.63	3.07
NPCC 3/	0.98	0.73	1.75	2.18	1.14	1.47	4.43	4.56	-0.10	0.98	-0.07	1.71
SERC	4.40	3.68	3.58	4.60	1.67	5.47	2.17	3.02	2.81	3.59	0.67	3.13
SPP	13.29	0.46	7.16	5.54	3.15	4.16	2.48	0.67	4.50	2.04	2.46	3.26
SUBTOTAL	2.61	3.37	3.91	3.89	2.71	3.47	2.48	2.14	3.08	1.90	1.11	2.81
ERCOT	4.18	1.16	3.55	3.30	1.99	0.24	5.95	3.28	7.53	4.94	2.45	3.44
WSCC 3/	2.84	1.81	3.94	6.79	1.71	2.22	5.19	4.65	2.62	2.19	2.37	3.35
U.S. TOTAL	2.76	2.93	3.89	4.36	2.48	3.01	3.20	2.68	3.32	2.19	1.44	2.95

1/ AS REPORTED IN ITEM 3-A OF THE COUNCIL REPORTS. NET DEPENDABLE CAPABILITY IS THE STEADY HOURLY OUTPUT WHICH GENERATING EQUIPMENT IS EXPECTED TO SUPPLY TO SYSTEM LOAD, EXCLUSIVE OF AUXILIARY POWER. FOR THE PURPOSES OF THIS TABLE "NET DEPENDABLE CAPABILITY" INCLUDES PUMPED STORAGE UNITS AND OTHER SOURCES WHICH MAY HAVE ENERGY SUPPLY LIMITATION, BUT WHICH ARE EXPECTED TO BE AVAILABLE DURING THE PEAK DEMAND PERIOD.

2/ TOTAL OF BULK POWER AND LIAISON SYSTEM MEMBERS.

3/ U.S. PORTION OF COUNCIL ONLY.

4/ AVERAGE OF TEN ANNUAL INCREASES FROM (1981-82/1980-81) TO (1990-91/1989-90).

5/ DOE STAFF HAS MODIFIED THE DATA REPORTED BY MAAC BY ASSUMING THAT TMI 2 WILL BE OUT OF SERVICE FOR THE WINTERS OF 1981-82 THROUGH 1987-88.

CAPABILITIES IN THIS COLUMN ARE FROM ERA-119M REPORTS FOR JANUARY 1981.

CHAPTER V
ALTERNATIVE SOURCES OF GENERATING CAPACITY

Various proposals have been made for the use of generating capacity sources different in one way or another from the types of sources in current use. Among these proposals are the following:

1. Ocean Thermal Electric Generation
2. Wind-Powered Generators
3. Geothermal energy as a power source
4. Solar energy as a power source
5. Fuel cells
6. Refuse, wood and biomass as a fuel sources
7. Fusion reactors
8. Breeder reactors
9. Cryogenic generating units
10. Satellite Power Systems

The April 1, 1981 Reliability Council reports (ERA-411) show that, of the list above, units using the following sources are projected for completion during 1981-1990:

Wind power
Geothermal energy
Solar Power
Fuel Cells
Refuse, wood and biomass as fuel sources

Only three Councils project the use of the alternative sources listed. The projected capacity data, taken from Item 2B of the ERA-411 reports, follow:

1. SERC - A 60 Mw installation with solid waste as a fuel is projected in the Florida section of the SERC report for completion in 1981.

2. NPCC - A total of 258 Mw of generating capacity using alternative sources is projected by NPCC for completion during the period 1981-1990 (See Table V.1).

3. WSCC - A total of 3809 Mw of generating capacity using alternative sources is projected by WSCC for completion during the period 1981-1990 (See Table V.2).

Table V.1
PROJECTED ALTERNATIVE GENERATING CAPACITY IN NPCC 1/
1981-1990

Year	Fuel Cell	Wood	Solid Waste	Refuse	Total
	Megawatts				
1981				32	32
1982					0
1983		46			46
1984			10	40	50
1985					0
1986			10		10
1987	10		50		60
1988					0
1989					0
1990			60		60
Total	10	46	130	72	258

1/ Summarized from the NPCC ERA-411 report dated April 1, 1981

TABLE V.2
PROJECTED ALTERNATIVE GENERATING CAPACITY IN WSCC 1/
1981-1990

YEAR	WIND	SOLAR	GEOTHERMAL	COGENERATION	SOLID WASTE	WOOD WASTE	FUEL CELL	TOTAL
	Megawatts							
1981	4	0	5	78	0	0	0	87
1982	4	0	374	77	0	0	0	455
1983	13	0	280	77	0	42	0	412
1984	0	0	310	0	40	40	0	390
1985	114	10	104	100	0	0	0	328
1986	12	7	138	0	0	55	25	237
1987	20	8	127	210	0	0	0	365
1988	22	125	486	0	0	0	25	658
1989	24	60	162	170	0	0	25	441
1990	28	100	203	50	0	0	55	436
Total	241	310	2189	762	40	137	130	3809

1/ Summarized from the WSCC ERA-411 report dated April 1, 1981

CHAPTER VI

System Reliability Indices and Council Area Reserve Margins

General Comments

Electric power system design, like the design of many large-scale systems, attempts to approach a desired objective as nearly as possible while recognizing practical limitations. As a result, compromises are made between the desired result and what is actually attainable. Limiting factors are constraints of time in which to implement a plan, costs, materials, manpower, state of the art and the impingement of electric power supply systems on other systems and entities that are needed by society. The goal of adequate, low cost, reliable electric power, while always in view, may not be totally attainable at all times in all parts of the country. It is a goal which is continually being approached. Some aspects of the success with which electric power systems approach the goal are measurable only in part, or by surrogates, for the desired characteristic. Substitution of a measurable quantity for a desired characteristic that cannot be readily measured is due in part to the large geographic extent of power systems, the diversity of customers and their power requirements, the sheer magnitudes of the power and energy quantities involved, and the uncertainties attached to the interactions between the system and the customers. The evolution of electric power systems has led to the use of some indices that are relatively simple to compute and appear to offer reasonable assurance that they represent, to some extent, the reliability of power supply to the system. The simple indices do not measure the reliability of supply to any specific customer or point on the electric system. The simplest measure of power supply adequacy is the generating capacity reserve margin. When not further qualified, "reserve margin" means the planned generating capacity reserve margin, or excess of installed generating capability over peak hour demand (peak load) of a system, before effect is given to 1) purchase and sale transactions with other utilities that may add to, or subtract from, the capacity a utility can count on to meet its load, 2) outages of generating capacity for various reasons, and 3) interruptible load. In this report, the term "Actual Reserve" is used to denote a calculated estimate of the reserve obtained by modifying the planned reserve to reflect the effects of items 1), 2), and 3), foregoing.

The reserve margin measure states the difference between installed capacity and the largest peak demand of the year (or of a season) in terms of either megawatts or percentage of the peak demand. This measure, as a guide to the adequacy of generating supply, has the advantage of being simple to compute. However, it is only a crude and superficial measure. It implies that all systems with a given reserve margin are equally reliable; this implication is by no means valid. The reserve margin usually is an "after-the-fact" measure: After the needed capacity has been established by more suitable means that integrate a number of important factors, the resulting reserve margin can be calculated. The margin computed by the Staff for each Council's projected seasonal peak demand is shown in Table VI.1.

Utility experience shows that it is not unusual for part of the planned generating capability to be unavailable from time to time because of necessary maintenance scheduled in advance, forced outages, or other reasons. In the detailed regional analyses of Chapter XIV, the possibility of capacity outages at the time of the summer and winter peak demands has been considered. For each region, a table has been incorporated in the analysis showing the possible reduction in capacity available at the time of peak demand for each of the three causes referred to above, and the resulting reserve. The Staff recognizes that the limited data sample it is using does not permit statistically rigorous computation (e.g., projected outage rates for Electric Regions are based on historical outages at only the peak hour for each of the previous four years); and the Staff plans to critically review its entire approach to reserve margin analysis prior to publication of the "Electric Power Supply and Demand -- Winter 1981-82" report. For this reason, the projected "actual" reserve margins used in this report should be considered as only gross indicators of power supply adequacy. Each table also shows the extent to which inter-regional transfers of capacity (net of purchases and sales) affects reserves. The last line of each regional reserve table shows the "Actual Reserve" (in %) that would result if the planned reserve is modified to account for possible capacity outages and for inter-regional transactions.

As a tentative guide to the adequacy of the "Actual Reserve", the Staff has used the following table:

Guide To Adequacy of Actual Reserve

If Actual Reserve Is	Regional Reliability Is
Negative	Inadequate
Greater than (or equal to) zero but less than 5%	Marginal
Greater than 5%	Adequate in most cases

This guide to adequacy has been developed for use only as a preliminary, broad scale measuring device to indicate, within wide limits, whether or not the projected capacity will enable a region to meet its projected peak seasonal demand. It is recognized that this guide will not be applicable in all situations and at all times. It is presented as an attempt to quantify preliminary judgments regarding the adequacy of percent reserve levels. It is not intended as a specification of what reserve levels "should be" in any specific instance.

Details

Various probability measures can be used to provide a stronger foundation than specifying a reserve margin for capacity planning, and for measuring the adequacy of any given plan. In general, these measures factor into the calculation the number and size of generating units, their reliability levels, and the patterns of customer demands. Account can also be taken of the probable ability of interconnections to supply capacity. A large number of papers have appeared in the technical literature (dating back to 1934), describing various calculating procedures for determining probability-based measures of generating capacity. Comprehensive discussions of the various methods have recently been published by the Department of Energy 1/ and the Electric Power Research Institute. 2/ The early studies of capacity adequacy measures generally ignored the geographically distributed nature of an electric power supply system and its loads. More recent studies have made some progress in combining data concerning generating capacity, loads, and the transmission system in order to measure reliability of supply to customers. When the transmission effects are incorporated in the analyses, the overall reliability of supply is seen to be less than that computed when consideration is not given to transmission effects.

In the Reliability Council ERA-411 Reports, reference is made to numerical measures (indices) of generating capacity adequacy, but these measures are not extended to include the effects of the transmission system. Different indices are used by the different Councils, as shown in the summary below, which is based on the April 1, 1981, ERA-411 Reports.

Measures of Capacity Adequacy Used by the Councils

ECAR

A probabilistic measure referred to as "Dependence on Supplemental Capacity Resources" (DSCR) is used to appraise the adequacy of generation.

ERCOT

Sufficient generating capacity is to be provided for the Texas Interconnected System, as nearly as possible, to insure a reserve of at least 15% of the forecasted maximum hour demand of the Texas Interconnected System.

1/ "The National Electric Reliability Study." April 1981. U.S. Department of Energy. DOE/EP-0005.

2/ "Reliability Indexes for Power Systems." Project 1353-1. Final Report March 1981. Prepared by General Electric Co., for Electric Power Research Institute.

MAAC

Sufficient megawatt generating capacity shall be installed to insure that in each year the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. Among the factors to be considered are the characteristics of the loads, the probability of error in the load forecast, scheduled maintenance requirements for generating units, forced outage rates of generating units, limited energy capacity, interconnections to other pools and network transfer capabilities within the MAAC system.

MAIN

MAIN Guide No. 6, "Procedure for Determination of Generation Reserve Requirements," is directed specifically to MAIN as a whole, but may be used by individual utilities or groups of utilities within MAIN. The criterion is a Loss-of-Load Probability (LOLP) of 0.1 day per year. The method used combines generating capacity outage probabilities with expected daily peak demands to give the expected risk of load exceeding capacity; it provides for consideration of the deviation of daily peak demand from the forecast value.

Individual systems and groups of systems within MAIN have criteria as follows:

Illinois - Missouri Pool (Central Illinois Public Service Company, Illinois Power Company, Union Electric Company). Included with Union Electric Company are its three subsidiaries, Missouri Power and Light Company, Missouri Edison Company and Missouri Utilities Company)

The planned level of pool reserve should be equal to (for each month) the larger of:

a. 15% of highest forecast monthly adjusted demand for the year.

b. 50% of the capability of the largest unit.

Wisconsin - Upper Michigan Systems

Reserve shall be at least 15% of the adjusted demand.

Central Illinois Light Company

Installed reserve shall be equal to 15% of the peak hour load or 50% of the largest liability, whichever is greater. ("liability" is not defined)

Commonwealth Edison Company

The reserve shall be 15% of native demand during the summer peak period and 24% of the native peak demand during the winter peak period. System net capability for the purpose of computing reserve margin is the sum of owned generating capability, Ludington Pumped Storage Plant allotment and the net of firm purchases, firm sales and diversity exchanges.

Western Illinois Power Cooperative

Minimum reserve shall be 15% of adjusted demand or 50% of the capability of the largest unit, whichever is greater.

Wisconsin Electric Power System

Planned reserve margin shall be 15%.

Columbia, Missouri Water and Light Department

Reserve criterion is 15% of Columbia's demand or 50% of the largest unit, whichever is greater.

Rochelle, Illinois, Municipal Utilities

The reserve criterion is 13.5% of demand.

Southern Illinois Power Cooperative

Installed reserve shall be 15% of peak hour demand.

City of Springfield, Illinois, Water, Light and Power

The reserve requirement is 18% of peak demand or 75 MW, whichever is larger.

Village of Winnetka, Illinois

Reserve criterion is based on the largest single source of power, whether scheduled import or a turbo-generator being out of service. This results in required reserve margins of approximately 50%.

MARCA

Each Party's [Party = Signatory to the MARCA Agreement] installed generating capacity (net capability) for any month, adjusted for power purchases and sales, shall be not less than its maximum integrated hour demand for that month plus a reserve of 15% (10% for a hydro system) of such demand for the 12-month period ending with the current month. Periodic reviews of the criterion shall include the effects of generating unit forced outage probabilities, power exchange arrangements with non-member systems, maintenance schedules, local patterns, and deviations from load forecasts.

NPCC

Each Area's[1]/ generating capacity will be planned in such a manner that--after due allowance for scheduled maintenance, forced and partial outages, interconnections with neighboring areas and available operating procedures--the probability of disconnecting non-interruptible customers due to generation deficiency, on the average, will be no more than once in ten years.

SERC

The SERC report does not provide a statement concerning a Council-wide criterion for generating capacity adequacy. Each sub-region of SERC, it appears, has an index of its own. The statements concerning these indices are given below.

Florida Coordinating Group (FCG).

Each year the FCG System Planning Committee conducts Loss of Load Probability studies to assess the relative level of generation reliability for the next ten years.

Southern

Installed reserve requirements are not based upon any one set of criteria. Among the factors considered are mix of generating resources, system operating practices, preventive maintenance practices, mutual emergency assistance contracts with neighboring utilities, interconnection with other utilities. Based on past experience, reserve margins of 20% to 25% offer a good target for expansion of bulk power facilities.

TVA

Sufficient megawatt generating capacity to insure that for each future year the probability of failure to supply load shall not exceed the acceptable reliability risk level. Factors considered in the calculation of the monthly loss of load probability are the characteristics of the monthly loads, the probability of error in the load forecast, generating unit forced outage rates, normal scheduled maintenance of generating units, limitations on the availabilities of thermal peaking capabilities above continuous capabilities, variations in hydro capacity, interconnections and agreements with other utilities. This statement applies to TVA's section of the SERC ERA-411 Reports in 1980 and 1981. The 1979 report stated that TVA's criterion was to maintain a reserve margin on a month-by-month basis which is equivalent to an expected reliability risk level of one day in ten years.

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[1]/ "Area" refers to New York Power Pool and NEPOOL.

VACAR

The report states, "Each member of VACAR has its own minimum reserve criteria. These criteria generally range from 20% to 25% of forecast."

SPP

Capacity available to the SPP system shall exceed the predicted annual peak load obligation by a margin of 20%. 1/ As an alternative, a probability study shall show that the probability of load exceeding capacity available shall not be greater than one day in ten years provided that in no case shall the reserve be less than the peak load obligation by 12%. The method employed in the probability study shall include consideration of uncertainty in prediction of load, the best available data on generator forced outage rates, the hour-by-hour characteristics of the load, availability of quick-start generation and the effects of interconnections and agreements with other utilities.

WSCC (U.S. Portion Only)

The following table, adopted by the WSCC Executive Committee on September 19, 1974, is reproduced from the April 1, 1981, WSCC Report under ERA-411 (p. 3B-30). It is only a recommendation to WSCC members; each member may have its own reserve criteria.

1/ This percentage was changed from the previous 15% by recent action of the SPP Engineering and Operating Committee.

WSCC Power Supply Design Criteria

Recommended Minimum Performance Table

It is recommended that areas or systems defined for analysis should meet or exceed at least one of the following WSCC criteria for installed and planned generating capacity:

	Criteria	Minimum Design Performance
1.	Monthly Reserve Capacity After Deducting Scheduled Maintenance (MW)	Greater of R, or the largest Risk, plus 5% of Load Responsibility[1]
2.	Monthly Reserve Capacity After Deducting Scheduled Maintenance (MW)	2 largest Risks
3.	Annual reliability criterion based on probability of loss of load--either	
	a. Frequency of loss of load, or	1 day in 10 years
	b. probability of meeting all loads in a year	0.90

Northwest Power Pool (NWPP)

West Group

The greater of i) or ii) below:

i) "Forced Outage Reserve" for the Pacific Northwest Coordination Agreement, sufficient to protect against loss of load to the extent that the probability of load loss in a contract year shall be no greater than the equivalent of one day in 20 years. The procedure shall be based on characteristics of peak load variability and generating unit forced outage rates. To the "Forced Outage Reserve" shall be added one-half year load growth for utility type load.

ii) 12% of firm peak load for the first year, increasing one percent per year to 20% and remaining at 20% thereafter.

Pacific Northwest Coordination Agreement:

The "Forced Outage Reserve" defined in (a) above.

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[1] Definitions

$$R = \left(\frac{.05\ H + .15\ T}{H + T}\right) \times L$$

H = Monthly hydro capability after deducting scheduled maintenance

T = Monthly thermal capability after deducting scheduled maintenance

L = Load Responsibility: System or area monthly firm peak load demand plus those firm sales minus those firm purchases for which reserve capacity must be provided by the supplier.

Reserve Capacity after Deducting Scheduled Maintenance = H + T - L

Risk: Capacity reduction caused by outage of a generator or transmission line.

[redacted]

Rocky Mountain Power Area (RMPA)

There is no formal installed reserve criterion, but for reporting purposes it has been agreed to use WSCC Criterion No. 1.

Arizona - New Mexico Power Area (A - NM)

There is no formal reserve criterion. Individual utilities have the following criteria:

Arizona Public Service Co.

Until May 1, 1983, reserve should equal 16% of (Peak Load - Firm Purchases - Interruptible)

Salt River Project

20% of estimated peak demand

Tucson Electric Power Co.

Installed capacity margin should be equal to the larger of 15% of peak load or the largest single hazard plus 50 MW. 1/

Arizona Electric Power Cooperative, Inc.

The reserve margin should be at least 20% of (Peak demand less firm purchases).

Arizona Power Authority

No reserve margin is maintained because the Authority acts only as a wholesaler of power.

Western Area Power Administration (Boulder City)

The largest unit generating on the system is covered.

Plains Electric Generation & Transmission Cooperative, Inc.

Reserve margin should be 20% of (Projected peak demand less firm purchases).

El Paso Electric Co.

Criterion 1 of the WSCC Criteria is followed.

Public Service Co. of New Mexico

The reserve margin should be the larger of 20% of peak load or the largest single hazard. 1/

California - Nevada Power Area

The California - Nevada Power Area consists of the Northern California - Nevada Power Area and the Southern California - Nevada Power Area. For several years, WSCC treated these areas separately, but now considers them as a single area. Staff considers it advisable to treat the two areas separately because of North-South transmission limitations within California.

The major utilities in the Northern California area are Pacific Gas & Electric Company (PG&E), Sacramento Municipal Utility District, USWP 2/ and WAPA 3/ Mid-Pacific

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1/ "Largest single hazard" is not defined in the ERA-411 Report.
2/ U.S. Water and Power Resources Service of the Department of the Interior.
3/ Western Area Power Administration of the Department of Energy.

Regions, Modesto Irrigation District, Turlock Irrigation District, City and County of San Francisco and California Department of Water Resources (CDWR). Those in Northern Nevada are Sierra Pacific Power Company (SPP) and Mt. Wheeler Power Company. Other organizations either serve retail loads with purchased power or sell the entire output of owned generation to another entity.

PG&E presently coordinates the power supply planning for most of the Northern California area, excluding California Department of Water Resources. SPP does the same for most of Northern Nevada. Of the total Northern California - Nevada load responsibility, PG&E is responsible for approximately 95 percent, SPP approximately 3 1/2 percent, and CDWR 1 1/2 percent.

The Southern California - Nevada Power Area consists of the area served by Southern California Edison Company, City of Anaheim, City of Riverside, the Metropolitan Water District of Southern California, San Diego Gas and Electric Company, Los Angeles Department of Water and Power, City of Glendale, City of Burbank, City of Pasadena, Nevada Power Company, State of Nevada, USWP at Boulder City, Lincoln County Power District, and C.P. National, Inc.

WSCC considers California - Nevada as a single Power Area, but no reserve margin criterion has been established for the area as a whole. Each utility uses its own criteria for reserves. The Division of Power Supply and Reliability has requested WSCC to report the Northern California - Nevada and Southern California - Nevada Power Areas separately. This has been done in the Supplement to the WSCC ERA-411 Report, but no reserve margin criteria are reported for these areas. Individual utility reserve criteria are reported below.

Pacific Gas & Electric Co.

(Area wide criteria covering major utilities in the Northern California - Nevada Area, as defined above.)

In the power area coordinated by PG&E, three reserve criteria are used to judge whether a resource plan provides a reliable power supply. The planned reserves, under adverse hydro conditions and after deducting scheduled maintenance, must satisfy all three criteria.

1. Monthly planned reserves shall equal or exceed 12 percent of the monthly peak demand, and average monthly planned reserves shall equal or exceed 12 percent of the annual peak demand.

2. Monthly planned reserves shall equal or exceed the two largest single contingency risks in service at the time of the monthly peak demand.

3. The expected loss of load probability shall not be greater than one day in ten years. The reliability calculation is made using a daily peak demand representation and includes the effect of reserve support over the interconnection to Southern California.

The first two criteria are the lower bounds to which PG&E will allow its reserves, without reserve support, to go -- even if probability analysis indicates otherwise. In most all cases, the criterion using LOLP calculations governs the need for resources.

The governing reserve required by the three criteria above is reported to WSCC under Criterion 3. This requirement is always more strict than WSCC's Criteria 1 and 2. Criterion 3 should only be applied to the Northern California - Nevada Area excluding the California Department of Water Resources and Sierra Pacific Power Company.

The Sierra Pacific Power Company's objective is to maintain a planned reserve margin greater than that required by WSCC's Criterion 1. The California Department of Water Resources' planned reserve criterion is 10 percent of their peak demand.

Southern California Edison Company

(Including City of Anaheim, City of Riverside, and the Metropolitan Water District.)

Southern California Edison Company resource programs are designed to meet or exceed each of the following three minimum criteria in each year of the forecast period:

1. Installed capacity margin of 18 percent, plus or minus 2 percent, of the annual estimated peak demand.
2. Installed capacity margin, after deducting scheduled maintenance, sufficient to allow the loss of the larger of (i) the two largest risks (generating unit or interconnection), or (ii) 7 percent of system demand plus the largest risk.
3. A reliability criterion that is based on probability calculations. The criterion requires that the resource program has at least a 95 percent certainty of being able to serve the forecast loads every hour of each year, allowing for planned generation maintenance and random forced outages, without requiring the delivery of additional capacity via Edison's interconnections more than approximately one hour every 20 years in excess of that assumed normally available.

SCE management reserves the right to modify these criteria, based on judgment, should conditions warrant.

San Diego Gas & Electric Co.

The reserve margin goal is 20% of annual peak demand before deducting maintenance.

Los Angeles Dept. of Water & Power

A loss-of-load probability criterion, and contingency criteria, are used for generating capacity evaluations. The loss-of-load criterion is one day in ten years, on the basis of hourly load information.

City of Burbank

The reserve margin is the largest single contingency.1/

City of Glendale

The reserve margin is the largest single contingency.1/

City of Pasadena

The reserve margin is the largest single contingency.1/

Nevada Power Co.

(Including State of Nevada, U.S. Water & Power Resources Service at Boulder City, Lincoln County Power District, and C.P. National, Inc.)

The planned reserve margin is 20% of the peak demand, plus 5% of the coal-fired generating capacity.

1/ "Largest single contingency" is not defined.

System Criteria For Contingencies

Reliable supply of electric power depends upon more than just an excess of generating capacity over demand at each instant. The power generated must move over switchgear, transformers, transmission lines, busses, and distribution circuits. Electric utilities have developed many techniques and procedures for designing the elements of power system networks. Some of the designs can be tested by actual physical trials. Many of the qualities of a power supply system, however, cannot be tested by physical means but can only be tested mathematically. The voltages, currents and power flows involved in testing the response of a network to a specified contingency are so large that physical testing is usually prohibitively expensive and impractical. Therefore, "simulated testing"1/ has come to be the established accepted practice of electric utilities for many characteristics of the electric power supply network. Certain conditions known to impose large stresses on a power network are applied to a mathematical representation (a model) of the system; and the resulting mathematical responses, which describe the behavior of the network, are evaluated. These "tests" are generally described by the terms "load flow study", "stability" or "transient stability study" and "fault study." The utility industry has come to more or less general agreement on this procedure but may differ in details.

The Reliability Councils have selected those tests they deem of basic importance and generally applicable to system design and testing. In view of the diversity of possible approaches to power system planning and design, it is not unusual that the criteria of the nine Councils are not absolutely uniform. The differences result from the difference among systems, the different requirements imposed on systems in different parts of the country, and the different experiences of planning engineers. Some of the Council criteria for network design are given below to indicate the nature and scope of the standards. Additional criteria and a more complete discussion of system reliability considerations can be found in each Council's ERA-411 Report.

1. ECAR

Reliability criteria for simulated testing are such as to assure that the bulk power supply network or any major part of it will not suffer uncontrolled areawide power interruptions under credible contingencies such as:

A. Sudden outage of any transmission circuit or transformer, at a time when any three generating units or any combination of generating units equal to 25-30% of system load within the area or sub-area being tested, whichever is greater, are out of service.

B. Sudden outage of any double-circuit transmission tower line at a time when any two generating units or any combination of generating units equal to 15-20% of system load within the area or sub-area being tested, whichever is greater, are out of service.

C. Sudden outage of any generating unit at a time when any two generating units or any combination of generating units equal to 15-20% of system load within the area or sub-area being tested, whichever is greater, are out of service.

1/ "Simulated" is understood to mean the testing of system models as represented by sets of mathematical equations that describe the relationships between electrical characteristics of the system. The "solutions" describe the reaction of the system to a specified set of conditions. This work is done on digital computers, with the results of the "test" appearing on computer printouts in the form of numbers representing voltages, electrical angles, currents, frequency, real power flows in megawatts and reactive power flows in kilovars. The general names for the types of studies performed are: load flow study, stability (or transient stability) study, and fault (or short circuit) study.

D. Sudden outage of any circuit at a time when any other transmission circuit or transformer and any two generating units or any combination of generating units equal to 15-20% of system load within the area or sub-area being tested, whichever is greater, are out of service.

E. Sudden outage of all generating capacity at any generating plant.

F. Sudden dropping of a large load or a major load center.

G. Sudden outage of all transmission circuits on a common right-of-way.

H. Sudden outage of any transmission station, including all generating capacity associated with such a station.

I. Sudden outage of any tower line at the time when any other one circuit or transformer is out of service, or vice versa.

2. ERCOT

ERCOT has adopted the following criteria for the Texas Interconnected Systems for simulated testing to assure that the system will not suffer "cascading breakup and collapse" because of contingencies such as the following:

A. Projected Texas Interconnected System planning will include simulated testing to insure that the system will not experience cascading breakup and collapse initiated by the occurrence of contingencies such as:

1) Loss of all generating capacity at any generating station.

2) Loss of any two generating units.

3) Outage of any circuit or generating unit during scheduled maintenance on any other transmission line or generating unit.

4) Outage of any single or double circuit transmission line, generating unit, transformer, or bus.

5) Simultaneous outage of overhead transmission lines parallel to each other for a substantial distance having a spacing between circuits of less than the height of the structures.

6) Any fault cleared by normal operation of backup relays.

7) Loss of any large load or concentrated load area.

3. MAAC

A. The tests which MAAC uses to examine system response are (among others):

1) Sudden loss of the entire generating capability of any station for any reason.

2) The outage of the most critical transmission line on any one of the interconnected systems as the result of a three-phase fault immediately following (i.e. before readjustment) the tripping of another critical line on the same or on an adjacent system.

3) The sudden loss of all lines of one voltage emanating from a substation.

4) The sudden loss of all lines on a single right-of-way.

5) The sudden dropping of a large load or a major load center.

6) The occurrence of a multi-phase fault with delayed clearing.

B. Network transfer capability: The amounts of power planned to be interchanged between areas within MAAC and between MAAC and neighboring pools shall be such that applicable ratings and stability, voltage, and relay limitations are not exceeded.

1) Extended period transfer: The maximum amount of capacity planned to be delivered from one area to another for economy interchange in normal day-to-day operations shall be limited as follows:

   a) With all transmission facilities in service and normal generator maintenance scheduling, all system components shall be within normal loading limits.

   b) With the outage of any single facility, the provisions of the transmission requirements section 1) shall apply.

2) Capacity emergency transfer: The maximum amount of capacity planned to be transferred from one area to another for capacity shortages shall be limited as follows:

   a) With all transmission facilities in service and normal generator maintenance schedules, the loadings of all system components shall be within applicable emergency ratings and stability limits, and no excessive voltage drops shall occur.

   b) The interconnected systems shall then be able to absorb the initial power swing resulting from the sudden loss of any one transmission line or generating unit.

   c) After the initial swing period, the loadings of all system components shall be within short-time emergency ratings and acceptable voltage limits.

4. MAIN

MAIN defines three measures of incremental[1] transfer capability that are to be tested:

First Contingency Incremental Transfer Capability
Second Contingency Incremental Transfer Capability
Installed Contingency Incremental Transfer Capability

In addition, the system is tested for response to simulated extreme disturbances. Among these are:

A. At peak load, with reasonable incremental interchange above projected base case schedules between the two systems most affected by the disturbance:

   1) Sudden outage of all generating capacity at any plant.

   2) Sudden outage of any transmission station, including all generating capacity associated with such a station.

   3) Sudden dropping of a large load or a major load center.

   4) Any other credible contingency of the same degree.

B. At peak load, with interchange equal to First Contingency Incremental Transfer Capability (FCITC) between the two systems most affected by the disturbance:

   1) Sudden outage of any transmission tower line at a time when any other circuit is out of service.

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[1] Capability in addition to existing or projected scheduled capacity transfers.

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[redacted]

2) Sudden outage of all transmission circuits on the same right-of-way.

3) Sudden outage of any single or double circuit transmission tower line associated with a station which has two generating units already out of service.

5. MARCA

A. Among the MARCA criteria are the following:

1) With the MARCA System initially normal (facility loadings and system voltages within normal limits and no prior outage), the system shall withstand the loss of any element without exceeding emergency voltage or emergency loading limits of any equipment prior to system readjustment, without remedial action or unacceptable system performance on other systems. During the outage of the element, the system must be capable of readjustment so that all voltages are within acceptable limits and all facility loadings within continuous ratings.

2) With any critical transformer, single transmission line (3Ø A.C. or monopole D.C.), or generator already out of service and operations adjusted to restore system security, the system shall withstand the subsequent loss of any remaining element, which could include a bus section, without exceeding emergency voltage or emergency loading limits of any facility. During the outage, the system must be capable of readjustment so that all voltages are within acceptable limits and all facility loadings within continuous rating.

3) With the MARCA System initially normal, the system shall withstand the loss of any double-circuit A.C. line, any bipolar D.C. line, or any combination of facilities resulting from failure of a circuit breaker to clear a fault, without exceeding emergency voltage or emergency loading limits of any equipment. During the outage, the system must be capable of readjustment so that all voltages and facility loadings are within applicable continuous limits.

4) With any critical transformer, line, or generator already out of service and operations adjusted to restore system security, the system shall withstand the loss of any double-circuit A.C. line, any bipolar D.C. line, or any combination of facilities resulting from failure of a circuit breaker to clear a fault, without service interruption to a major portion of the MARCA system. During the outage, the system must be capable of readjustment so that all voltages and facility loadings are within applicable emergency limits.

B. Probable Disturbance

Stability of the MARCA interconnected systems shall be maintained without interruption of load due to instability or cascading during and after the most severe cases of each of the types of disturbances listed below for peak load levels and critical off-peak load and generation levels. Where service to a major portion of the MARCA system is jeopardized, these requirements will also apply during the outage of any critical transformer, line or generator, and operations adjusted to restore system security.

1) A permanent three-phase fault on any element, with normal clearing, with due regard to automatic reclosing, if used. Also, the system must be adequate for testing of an outaged transmission line by manual reclosing during the outage and before adjusting any generation if this is a normal system operating practice.

2) Simultaneous permanent single line-to-ground faults on both circuits of a double-circuit line, with normal clearing, with due regard to automatic reclosing if used.

[redacted]

3) A permanent single line-to-ground fault on any element with delayed clearing and due regard to automatic reclosing if used. This delayed clearing could be due to circuit breaker, relay system, or signal channel malfunction.

4) Simultaneous permanent line-to-ground faults on both poles of a bipolar D.C. line with due regard to automatic re-start sequence if used.

5) Sudden loss of any element without a fault.

C. Extreme Disturbance

It is impossible to anticipate or test for all disturbances that can occur on the present and future MARCA system. Simulating extreme disturbances, however, can serve as a means to measure the ability of the MARCA system to withstand less probable contingencies, some of which may not be readily apparent. These tests are prescribed only as a practical means to study the MARCA system for its ability to withstand disturbances more severe than those defined in Section B. Tests by simulation will be made from time to time by the MAPP Reliability Subcommittee to determine the effects of extreme disturbances on the performance of the MARCA members to insure system development is designed to minimize the spread of any interruption that might result from:

1) The sudden loss of the entire capability of a generating station.

2) The sudden loss of all lines from a generating station, switching station, or sub-station due to a simultaneous three-phase fault.

3) The sudden loss of all circuits on a common right-of-way due to a permanent three-phase fault on each circuit.

4) The sudden dropping of a large load.

6. NPCC

Among the tests and criteria adopted by NPCC on September 20, 1967, and revised as of May 14, 1980, are the following:

A. Stability is to be maintained during and after the most severe of the following contingencies:

1) A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section that is cleared in normal time, with due regard to reclosing facilities.

2) Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple-circuit tower that are cleared in normal time, with due regard to reclosing facilities.

3) A permanent phase-to-ground fault on any generator, transmission circuit, transformer or bus section with delayed clearing and with due regard to reclosing facilities.

4) Loss of any element without a fault.

5) A permanent phase-to-ground fault on a circuit breaker that is cleared in normal time, with due regard to reclosing facilities.

B. The NPCC criteria also specify that the effect of the following "possible but improbable" contingencies should be studied.

1) Loss of the entire capability of a generating station.

2) Loss of all lines emanating from a generating station, switching station, or sub-station.

[redacted]

3) Loss of all transmission circuits on a common right-of-way.

4) Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to circuit breaker, relay system, or signal channel malfunction.

5) The sudden dropping of a large load or major load center.

6) The effect of severe power swings arising from disturbances outside the Council's interconnected systems.

7) A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time, and failure of associated generation rejection or transmission cross-tripping relay systems to operate.

7. SERC

The SERC regional criteria are directed to the prevention of cascading, which is defined as "the uncontrolled successive loss of system elements triggered by an incident at any location." Each of the SERC member systems is to be planned so as to avoid cascading under the following situations:

A. Loss of Generation

Sudden loss of entire generating capability in any one plant.

B. Loss of Load

Sudden loss of a large load or major load center.

C. Loss of Transmission

1) The outages of the most critical transmission line caused by a three-phase fault during the outage of any other critical transmission line.

2) Sudden loss of all lines on a common right-of-way.

3) Sudden loss of a substation (limited to a single voltage level within the sub-station plus transformation from that voltage level), including any generating capacity connected thereto.

4) Delayed clearing of a three-phase fault at any point on the system due to failure of a breaker to open.

8. SPP

Among the criteria for system planning in the Southwest Powdr Pool are the following, which apply to the several sub-areas of SPP:

A. Each sub-area shall maintain service continuity after the loss of the single most important system component (either transmission line or generating unit), taking into account planned maintenance schedules.

B. Stability shall be maintained between the sub-area and neighboring systems when the loss of the system component described in Subsection A, of this section, was caused by a three-phase fault at the worst location cleared in 0.1 second.

C. A sub-area may suffer interruption of load as a result of less probable contingencies; however, such contingencies should not result in the collapse of the Southwest Power Pool system. These less probable contingencies shall include, but not be limited to, the following:

[redacted]

1) The loss of a complete sub-station or switching station (all equipment of one voltage).

2) The loss of all units in a generating station which have in common such components as transmission sub-station, control room, fuel supply, etc.

3) The loss of all transmission lines on a common right-of-way.

4) The loss of any two generating units in the same sub-area during annual peak conditions (whether scheduled or not).

5) The loss of any two transmission lines in the same sub-area during annual peak conditions.

9. WSCC

WSCC, in Section 6-D of its April 1, 1981, ERA-411 Report, discusses the performance standards used in its assessment of interconnected system reliability. The Council criteria have two objectives: (i) Primary - continuity of service to loads; and (ii) Secondary - preservation of interconnected system operation during disturbances.

In addition to stating some general principles relating to normal system operation, WSCC provides criteria for dynamic performance in terms of "performance levels." These performance levels are defined by WSCC as follows:

A. Post-disturbance line loadings and sub-station voltages are allowed to exceed normal limits but not emergency limits prior to system readjustment. No remedial action or abnormal system performance is required.

B. Some remedial action is permitted, such as the dropping of interruptible load, and generator dropping or an equivalent reduction in energy supplied to the system.

C. Remedial actions in addition to those of Level B are allowed, such as controlled opening of interconnections and other lines, "system islanding" and underfrequency load shedding.

D. Additional remedial action beyond Level C may be needed, such as controlled dropping of firm load, further islanding and disconnection of generators from the system. Post-disturbance transmission loadings and sub-station voltages may exceed emergency limits prior to readjustment.

[redacted]

The performance levels described are summarized in the table below, from p. 6D-8 of the WSCC ERA-411 Report dated April 1, 1981.

Performance Levels

Allowable Conditions or Actions on Interconnected Systems*	* Performance Level * A	B	C	D
Remedial Action	No	As Permitted Below		
Dropping of Interruptible Load	No	Yes	Yes	Yes
General Dropping or Equivalent Reduction of Energy Input to the System	No	Yes	Yes	Yes
Controlled Opening of Interconnections and/or Other Lines Including System Islanding and Attendant Underfrequency Load Dropping, if required	No	No	Yes	Yes
Controlled Dropping of Firm Load	No	No	No	Yes
Sub-Islanding and Generation Separation May Occur	No	No	No	Yes
Post Disturbance Loadings and Voltages Outside of Emergency Limits Prior to Readjustment	No	No	No	Yes

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* Action or conditions on systems other than the one on which disturbance occurred.

** A "Yes" indicates the action or condition is permitted in simulation testing to meet the performance level if required to prevent cascading. A "No" indicates that the action or condition is not allowed.

The application of the performance levels to ten specific contingencies is shown in the table below, reproduced from p. 6D-8 of the WSCC ERA-411 Report dated April 1, 1981.

WSCC Disturbance - Performance Table

Disturbance	No Fault	1/	3-Phase Fault w/Normal Clearing			
			One Generator Out System Readjusted		One Line Out System Readjusted	
Prior Condition of System	Normal	Normal	Yes	No	Yes	No
Element Lost or Faulted						
Load	A	A	A	A	A	A
Transformer	A	A	A	A	A	B
Line	A	A	A	A	B	C
Generator	A	A	A	B	A	C
Bus Section	B	B	B	B	C	C
2 Generators	C	C	C	D	C	D
2 Lines	C	C	C	D	C	D
All Lines on Right of Way	D	D	D	D	D	D
Entire Sub-station	D	D	D	D	D	D
Entire Plant w/Switchyard	D	D	D	D	D	D

1/ 30 fault w/normal clearing or Single-Phase-To-Ground Fault w/stuck breaker.

TABLE VI.1

ACTUAL AND PROJECTED SUMMER AND WINTER RESERVE MARGINS
AS REPORTED APRIL 1, 1981 BY THE REGIONAL ELECTRIC RELIABILITY COUNCILS
CONTIGUOUS UNITED STATES

% RESERVE MARGIN AT TIME OF SUMMER PEAK DEMAND 1/

	ACTUAL 1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
ECAR 2/	36.38	30.99	30.53	34.73	36.40	37.80	38.41	36.30	34.75	35.27	32.33
MAAC	28.66	32.83	32.32	31.75	30.87	29.02	26.54	25.73	29.97	28.80	28.91
MAIN	30.37	17.47	17.49	20.98	24.04	24.94	25.13	25.18	24.37	22.40	19.04
MARCA 3/	25.61	30.03	31.62	33.86	29.32	26.75	26.74	22.86	20.97	19.66	16.30
NPCC 3/	30.96	42.31	40.04	43.80	41.22	43.55	44.05	47.99	47.49	44.24	42.07
SERC	23.97	33.02	33.19	32.60	32.99	32.23	31.43	31.07	31.29	31.35	28.27
SPP	14.55	23.81	26.92	29.43	27.15	28.22	26.07	22.69	23.92	21.22	19.76
SUBTOTAL 4/	28.05	32.58	32.33	32.54	32.24	32.51	31.90	30.95	31.03	30.02	27.60
ERCOT	30.75	31.09	28.00	24.99	25.69	19.77	19.79	19.92	19.22	20.56	20.57
WSCC 3/	33.99	29.89	32.00	35.10	34.81	33.45	33.74	36.30	36.43	34.83	33.54

% RESERVE MARGIN AT TIME OF WINTER PEAK DEMAND 1/

	1980-81	1981-82	1982-83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
ECAR 2/	43.10	39.75	39.06	36.91	39.94	39.26	39.27	35.45	36.47	34.58	31.88
MAAC	51.56	58.96	57.23	55.32	52.43	50.17	45.88	46.57	47.44	45.10	44.50
MAIN	55.92	46.32	51.18	55.42	56.23	54.13	53.14	48.98	47.82	43.46	40.69
MARCA 3/	43.54	57.73	51.09	50.36	44.01	45.02	40.45	36.72	36.12	32.13	28.27
NPCC 3/	48.45	50.38	58.13	50.03	48.55	47.75	51.19	54.46	50.77	48.67	45.19
SERC	30.34	35.00	34.49	36.24	33.94	36.51	34.30	33.71	33.42	33.72	30.51
SPP	74.49	68.42	73.74	75.68	73.84	74.85	71.35	66.25	67.13	64.22	61.79
SUBTOTAL 4/	45.25	46.34	46.45	46.89	45.92	46.13	44.74	42.92	42.71	40.92	38.15
ERCOT	81.48	71.50	78.21	68.18	63.86	56.15	57.02	54.52	58.87	59.43	55.54
WSCC 3/	37.63	36.81	36.89	41.31	38.48	35.82	37.59	39.87	37.76	35.97	37.24

1/ $\% \text{ RESERVE MARGIN} = \frac{\text{NET DEPENDABLE CAPABILITY} - \text{PEAK DEMAND}}{\text{PEAK DEMAND}} \times 100$

2/ TOTAL OF BULK POWER AND LIAISON SYSTEM MEMBERS.

3/ U.S. PORTION OF COUNCIL ONLY.

4/ THIS INFORMATION IS MEANINGFUL TO SOME DEGREE, BECAUSE THE SEVEN COUNCIL AREAS ARE INTERCONNECTED. IT IS NOT HOWEVER IMPLIED THAT THESE RESERVES CAN BE FREELY EXCHANGED AMONG ALL REGIONS. ERCOT HAS NO INTERCONNECTION WITH OTHER COUNCIL AREAS. WSCC HAS ONLY MINOR INTERCONNECTION CAPACITY WITH OTHER COUNCILS.

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CHAPTER VII
GENERATING UNIT DELAYS

The construction and licensing of generating units is subject to delay for many reasons. Some of the reasons apply to the construction of any large project: natural disasters, financial problems, late delivery of equipment, labor difficulties, managerial and supervisory problems in project coordination. Other reasons for delay derive from the nature of utility systems: financial problems, reduced load growth forecasts, which change the point in time for which a generating unit is needed; delays of associated facilities (such as transmission lines) which would prevent use of the generator's full capacity if it were completed on schedule; regulatory delays, which may require redesign and rebuilding of some phases of construction or which may prevent completion of construction or operation until legal issues have been settled.

Nuclear Units

Experience has shown that nuclear units are highly susceptible to delays because of legal challenges and the requirement that the Nuclear Regulatory Commission issue construction permits and operating licenses. The construction of nuclear and non-nuclear generating units may be delayed pending issuance of permits and authorizations by various government agencies, but only nuclear units are required by Federal law to have an operating license (issued by the Nuclear Regulatory Commission) before becoming operational.

Table VII.1 shows the total new nuclear capacity currently projected by each Council for completion prior to the summer peaks of 1985 and 1990; Table VII.2 lists each individual unit, showing the completion date as scheduled in April, 1980 and in April 1981.

Table VII.1
Total New Nuclear Capacity
Projected for Completion by the Reliability Councils
As Reported April, 1981

Council Area	Total New Nuclear Capacity (in Megawatts) Scheduled Prior To The Summer Peak of	
	1985 1/	1990 2/
ECAR	4448	9425
ERCOT	3550	5950
MAAC	4286	6416
MAIN	6496	9886
MARCA	0	0
NPCC	3237	6626
SERC	11786	23246
SPP	4499	5749
WSCC	8181	14503
Total	46483	81801

1/ Scheduled between January 1, 1981 and June 1985
2/ Scheduled between January 1, 1981 and June 1990

Table VII.2
Changes in Nuclear Unit Operating Dates Based on Data Reported April 1, 1980, and April 1, 1981 In The Reliability Council ERA-411 Reports

Unit	Design MW	Operating Date Projected	
		April 1, 1980	April 1, 1981
		ECAR	
Zimmer 1	810	Jan. 1981	June 1982
Midland 2	818	Sep. 1984	Dec. 1983
Fermi 2	1123	Mar. 1982	Dec. 1983
Perry 1	1205	May 1984	May 1984
Midland 1	492	Mar. 1985	July 1984
Beaver Valley 2	852	May 1986	May 1986
Marble Hill 1	1130	Oct. 1982	Dec. 1986
Marble Hill 2	1130	Jan. 1984	Dec. 1987
Perry 2	1205	May 1988	May 1988
Bailly N-1	660	Jun. 1987	June 1989
Total	9425		
		ERCOT	
Comanche Peak 1	1150	Aug. 1981	June 1982
South Texas Project 1	1250	Feb. 1984	Feb. 1984
Comanche Peak 2	1150	Jan. 1983	March 1984
South Texas Project 2	1250	Feb. 1986	Feb. 1986
Allens Creek 1	1150	Nov. 1987	Dec. 1988
Total	5950		
		MAAC	
Salem 2	1115	Oct. 1980	April 1981
Susquehanna 1	1052	Jan. 1982	March 1982
Susquehanna 2	1052	Jan. 1983	May 1983
Limerick 1	1067	May 1985	April 1985
Hope Creek 1	1067	May 1985	Dec. 1986
Limerick 2	1065	May 1987	Oct. 1987
Hope Creek 2	1067	May 1987	Dec. 1989
Total	7485		
		MAIN	
LaSalle County 1	1078	Dec. 1980	Dec. 1982
Callaway 1	1150	Oct. 1982	April 1983
Clinton 1	950	Dec. 1982	Aug. 1983
LaSalle County 2	1078	Dec. 1981	Oct. 1983
Byron 1	1120	Oct. 1982	Oct. 1983
Byron 2	1120	Oct. 1983	Oct. 1984
Braidwood 1	1120	Oct. 1983	Oct. 1985
Braidwood 2	1120	Oct. 1984	Oct. 1986
Callaway 2	1150	Apr. 1988	April 1988
Total	9886		

[redacted]

Table VII.2 (continued)

Unit	Design MW	Operating Date Projected	
		April 1, 1980	April 1, 1981
		MARCA	
		No Nuclear Units Projectd Through 1990	
		NPCC	
Shoreham	849	May 1981	Dec. 1982
Seabrook 1	1194	Apr. 1983	Apr. 1983
Seabrook 2	1194	Feb. 1985	Feb. 1985
Millstone 3	1159	May 1986	May 1986
Nine Mile 2	1080	Nov. 1986	Nov. 1986
Pilgrim 2	1150	Dec. 1985	Nov. 1987
Total	6626		
		SERC	
Sequoyah 1	1140	Jun. 1980	Mar. 1981
McGuire 1	1180	Dec. 1980	Jul. 1981
Farley 2	829	Sep. 1980	Jul. 1981
Summer Nuclear 1	900	Dec. 1980	Jun. 1982
Sequoyah 2	1140	Jun. 1981	Jul. 1982
Watts Bar 1	1165	Sep. 1981	Nov. 1982
St. Lucie 2	842	- 1983	- 1983
McGuire 2	1180	Jul. 1982	Jun. 1983
Watts Bar 2	1165	Jun. 1982	Aug. 1983
Catawba 1	1145	Dec. 1983	Mar. 1984
Vogtle 1	1100	Nov. 1984	May 1985
Harris 1	915	Mar. 1984	Sep. 1985
Catawba 2	1145	Jul. 1985	Sep. 1985
Bellefonte 1	1235	Sep. 1983	Dec. 1985
Bellefonte 2	1235	Jun. 1984	Sep. 1986
Vogtle 2	1100	Nov. 1987	Nov. 1987
Yellow Creek 1	1285	Nov. 1985	Apr. 1988
Harris 2	915	Mar. 1987	Mar. 1988
Hartsville A1	1205	Jul. 1986	Jul. 1988
Phipps Bend 1	1220	Mar. 1987	Feb. 1989
Hartsville A2	1205	Jul. 1987	Apr. 1989
North Anna 3	907	Oct. 1987	Oct. 1989
Total	24153		
		SPP	
Grand Gulf 1	1250	Apr. 1982	June 1982
Waterford 3	1165	Feb. 1982	March 1983
River Bend 1	934	Apr. 1984	April 1984
Wolf Creek 1	1150	Apr. 1984	April 1984
Grand Gulf 2	1250	Apr. 1985	April 1988
Total	5749		

Unit	Design MW	Operating Date Projected April 1, 1980	 April 1, 1981
	WSCC		
Diablo Canyon 1	1084	Feb. 1981	July 1981
San Onofre 2	1140	Jul. 1981	Sep. 1981
Diablo Canyon 2	1106	Aug. 1981	Mar. 1982
San Onofre 3	1140	Jul. 1982	Aug. 1982
Palo Verde 1	1304	May 1983	May 1983
WNP 2	1103	Sep. 1981	Sep. 1983
Palo Verde 2	1304	May 1984	May 1984
WNP 1	1267	Dec. 1983	Feb. 1986
Palo Verde 3	1304	May 1986	May 1986
WNP 3	1242	Dec. 1984	Sep. 1986
WNP 4	1267	Jun. 1985	Feb. 1987
WNP 5	1242	Jun. 1986	Sep. 1987
Total	14503		

Most of the nuclear units scheduled for completion through 1990 are of large size (800 MW and larger) and will therefore have a significant impact on Electric Region reserve margins. A total nuclear capacity of 46,483 MW is reported by the Councils as scheduled for completion prior to summer 1985. Table VII.3 illustrates the effect on reserve margins for each Concil area in summer 1985, if nuclear capacity scheduled prior to the peak is delayed beyond the summer peak.

Table VII.3
Effect of Delay of Nuclear Capacity
Beyond Summer 1985

Council Area	Reserve Margins At Time of 1985 Summer Peak Demand If the following percentage of Now-Planned Nuclear Capacity Were to Experience Delay Beyond That Period: 0%	 10%	 25%	 50%	 100%
ECAR	37.80	37.20	36.31	34.82	31.84
ERCOT	19.77	18.87	17.53	15.28	10.79
MAAC	29.02	27.89	26.19	23.36	17.69
MAIN	24.94	23.29	20.82	16.70	8.46
MARCA	26.75	26.75	26.75	26.75	26.75
NPCC	43.55	42.71	41.45	39.34	35.14
SERC	32.23	31.08	28.64	26.50	20.76
SWPP	27.80	26.93	25.63	23.47	19.14
WSCC	33.45	32.53	31.15	28.85	24.25

The Councils that would be most severely affected by a delay beyond summer 1985 of half of the nuclear capacity projected are MAIN and ERCOT.

In addition to the deterioration of reliability that results from delayed completion of nuclear units, additional costs result from such delays. Those costs are discussed in Chapter VIII.

Coal Units

Projected coal units are subject to delay for much the same reasons that affect nuclear units, except that there is no single Federal agency that exercises authorities similar to those exercised by NRC with respect to nuclear units. Coal-fired generating units are, on the average, smaller than nuclear units. Therefore, in most instances the delay of a single coal unit has less effect on regional reliability than does the delay of a single nuclear unit. However, the aggregate planned capacity addition of coal-fired units is roughly equivalent to the aggregate planned nuclear addition, and delays in construction and licensing of coal units would have similar adverse effects on reserve margins.

Table VII.4 shows that the coal-fired generating capacity projected in 1981, for the period 1981-1989, decreased from that projected in 1980 for the same period. The decrease in megawatts is 18.52% and the decrease in the number of units is 16.19%. The table includes units with coal as the only fuel, units with coal as the primary fuel and oil as the alternate fuel, and units designed for oil as the primary fuel and coal as the alternate fuel.

Table VII. 4
Comparison of New Coal-Fired Capacity Through 1989
As Projected in 1980 and in 1981
By The Reliability Councils

Council Area	Projected in 1980		Projected in 1981	
	MW	No. of Units	MW	No. of Units
ECAR	22775	38	16948	30
ERCOT	14162	24	7603	14
MAAC	2800	6	2655	5
MAIN	3045	8	3475	9
MARCA	8688	20	8152	18
NPCC	2918	4	1893	3
SERC	17586	31	14534	27
SPP	21230	40	17944	32
WSCC	16886	39	16499	38
Total	110088	210	89703	176

[redacted]

CHAPTER VIII

Cost of Operating License Delays for Nuclear Units

Introduction

This chapter presents estimates of the cost of delays in the issuance of operating licenses by the Nuclear Regulatory Commission (NRC). At the request of NRC, the Department of Energy (DOE) began, in April 1981, a monthly review of the nuclear units for which such delays are expected. Data on the cost of delays for each unit was collected and analyzed. Two sets of estimates are presented -- one provided by the operating utilities, and the other developed independently by DOE staff.

It is recognized that delay of operation of any generating unit, whatever the cause, is likely to result in additional costs to a utility and its customers. However, this analysis deals only with the cost of delays in the issuance of operating licenses for nuclear units.

Length of Delays

Table VIII.1 identifies the nuclear units for which completion of construction is projected (or has occurred) one or more months before the projected issuance of an operating license by the NRC. The table shows two sets of estimates--one made in April 1981, and one made in June 1981 after NRC proposed a number of changes in its procedures that would reduce the licensing delays.

"Delay" is defined as the number of reactor months lost, which is equal to the interval between the utilities projected date of completion (Table VIII.1, columns 4 and 5) and the NRC's projected date of issuance of operating license (Table VIII.1, columns 2 and 3). For those units that have already been completed, the length of delay is the interval between the current month and the NRC's projected date of operating license issuance.

Since April 1981, the total number of months of delay[1] has decreased from 95 to 41 for several reasons:

- First, the NRC's proposed changes to its Rules of Practice should result in a savings of 2 months for each of nine reactors.
- Revisions in the schedule of the Atomic Safety and Licensing Board (ASLB) actions for McGuire 1, Susquehanna 1, Summer 1, and Comanche Peak 1, were assumed to save an additional 12 months.
- The completions of Susquehanna 1 and Summer 1 were delayed by 10 months and 3 months, respectively, from scheduled completion as of April 1981.
- A delay for Susquehanna 2 is no longer projected. In May, the Salem 2 unit received its full power license. The construction of Shoreham 1 has been delayed resulting in the unit no longer being impacted.
- Finally, since past delays are excluded (i.e., delays are calculated from the current month), delays for those units which have already been completed automatically decreased by 2 months from April to June.

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[1] Three Mile Island No. 1 is excluded from consideration here. It is a unit which has had an operating license since 1974, but NRC has decided that it should be kept in non-operating status, as a result of the accident at Three Mile Island No. 2.

[redacted]

Direct Costs of the Delay

The cost of a delay in issuance of an operating license after a plant is physically complete is equal to:

- The total costs the entire utility system (or systems, if the unit is jointly owned) would incur to satisfy its customers' energy requirement, based on the delayed licensing schedule, minus

- The total costs of satisfying the same energy requirement if the license had been issued when the plant was complete.

This cost differential is affected only by cost elements that change as a result of the delay; for example -- fuel, purchased power, maintenance, and other special expenses. It is not affected by anticipated monthly capital carrying charges or by any other costs that would be incurred with or without the delay.

The estimated direct costs of delay are summarized in Table VIII.2, based on two independent sources:

- One set of estimates (columns 1 through 4) was based on revised data obtained from the owners of the units;

- A second set of estimates (columns 5 through 8) was developed independently by the Staff based on available data on generating resources, pooling arrangements, load projections, capacity factors, and fuel prices. The key assumptions used in this analysis are summarized in Table VIII.3.

Due to the decrease in the months of delay from April to June, the total direct cost of delays has decreased from \$2233 million to \$934 million based on company estimates and from \$1589 million to \$812 million based on the Staff estimates.

Both sets of estimates used the same length-of-delay information (from Table VIII.1 columns 6 and 7).

Replacement power is the dominant contributor to the cost of licensing delays. The two most important factors affecting replacement power cost are:

- The amount of energy that must be replaced -- the number of lost kilowatt hours of reactor output resulting from the delay; and

- The mix of fuels used to generate the replacement power (oil, gas, coal, nuclear, etc.)

Amount of lost energy: The utilities assumed a capacity factor corresponding to a "mature" nuclear unit -- one that has operated for several years. Capacity factors are normally somewhat lower for "immature" units, so the number of kilowatt-hours actually lost during the delay is likely to be less than the number estimated by the utilities. The Staff agrees that a "mature" capacity factor is appropriate for estimating the total kilowatt-hour loss but has chosen, based upon recent past performance (see Reference 1), a numerical value (60 percent) that is more conservative than most utilities used.

Fuel Mix: The utilities used a variety of methods to estimate the mix of fuels used to generate replacement power. The Staff used the same general approach for all units, but added various judgmental assumptions based on knowledge of certain system-specific operating conditions. (For example, units that would operate as part of an integrated power pool were analyzed on the basis of the entire pool, rather than on the basis of the individual utility.)

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The Staff used the following analytical approach for estimating the mix of fuels:

- Estimate the amount of electric energy that must be produced, using recent load projections (see Reference 2);
- Identify the generating resources available to produce this energy, not including the delayed nuclear unit (see Reference 3);
- Remove from consideration (as contributors of replacement power) those resources whose level of operation would be unlikely to change as a result of adding the nuclear units (These are generally the units with the lowest operating costs or with limitations on their operating hours or fuel availability);
- Estimate, based on recent history (see Reference 4), the amount of energy contributed by each of the remaining classes of units (which generally include coal, oil, and possibly gas-fired units);
- Estimate the reduction in operation of each class of unit if the nuclear unit is added, taking into account:
    - Preferential reduction of units with highest fuel costs;
    - Predominance of units of each fuel type;
    - Physical operating considerations; and
    - Other system-specific factors.
- Calculate the total costs saved by this reduction in operation, using the fuel costs and heat rates in Table VIII.3;
- Subtract the fuel costs for the nuclear unit, assumed to be 0.6 cents per kilowatt-hour; and
- Assume the operating and maintenance (O&M) costs per kilowatt-hour are the same for the nuclear unit and the alternate sources.

An important feature of the Staff's approach is that it does not assume that the units with the highest fuel costs (i.e., the oil-fired units) would be the only units to have their operation reduced when a new nuclear unit is placed in service. Although a utility would prefer to reduce the use of high-cost units, there are many operating considerations that require such units to be used. Experience has shown that the introduction of a new baseload unit causes a change in the operating levels of many units on the system, including units with relatively low operating costs. The Staff, allocating the reduced operation among different classes of generators, used judgmental approximations which, although not exact, were generally consistent with this experience.

Capacity charges were not taken into consideration in the Staff analyses. Most of the utilities indicated that the replacement power for the delayed nuclear units would be generated within their own systems. It is possible that, in some cases, there would be a capacity charge for purchased power, but Staff has no current basis for estimating its cost.

The Staff's assumptions generally resulted in estimates for the monthly cost of replacement power (Table VIII.2, columns 5 and 6) lower than those provided by the utilities (column 1). In addition, a few utilities claimed special additional costs associated with the delay (footnoted in column 1). The Staff did not attempt to estimate such costs.

Table VIII.1

Data on Nuclear Units With Operating License Delays 1/ 1981

Unit	Capacity (MW) (1)	Projected Date of Issuance of Operating License Apr (2)	Jun (3)	Completion Dates Projected by Companies Apr (4)	Jun (5)	Months of Delay (2)-(4) Apr (6)	(3)-(5) Jun (7)	Replacement Power Fuel (8)	Source (9)
Comanche Peak 1	1,150	02/83	10/82	12/81	12/81	14	10	Gas	Self-generated
Diablo Canyon 1	1,084	02/82 2/	01/82 2/	01/81	01/81	11 6/	8 6/	Oil	Self-generated
Diablo Canyon 2	1,106	03/82 2/	01/82 2/	10/81	10/81	5	3	Oil	Self-generated
McGuire 1	1,180	12/81	06/81	01/81	01/81	9 6/	1 6/	Coal	Self-generated
Salem 2	1,115	04/81	05/81	04/80	04/80	1 6/	0	Oil-Coal	Purchased
San Onofre 2	1,100	04/82	02/82	06/81	06/81	10	8	Oil	Self-generated
Shoreham 1	854	10/82	08/82	05/82	09/82	5	0	Oil	Self-generated
Summer 1	900	06/82	01/82	08/81	11/81	10	2	Coal-Oil	Self-generated
Susquehanna 1	1,050	11/82	06/82	06/81	04/82 5/	17	2	Oil-Coal 4/	Self-generated
Susquehanna 2	1,050	11/82	04/83	09/82	04/83 5/	2	0	Oil-Coal 4/	Self-generated
Waterford 3	1,165	01/83	11/82	10/82	10/82	3	1	Oil	Purchased/ Self-generated
Zimmer 1	810	07/82	05/82	04/82	11/81	8	6	Coal-Oil	Self-generated
Total (new units)	- - -	- - -	- - -	- - -	- - -	95	41		
T M I 1	776	10/81 3/	10/81 3/	-	-	7 6/	5 6/	Oil-Coal	Purchased

Sources: Utility Companies and Nuclear Regulatory Commission

1/ Covers all units for which construction is expected to be completed at least 1 month before operating license is issued.

2/ According to company sources, the NRC projected dates do not reflect expediting procedures available to the Commission.

3/ TMI 1 has received an operating license and has been in operation. However, the unit was taken out of service for a routine refueling during February 1979, and was not allowed to return to service following the TMI 2 accident. The company anticipates that TMI 1 modifications will be completed by the end of 10/81. NRC projects a decision will be made on the unit in 10/81.

4/ Delay would reduce utility's coal-fired exports which would replace power in the PJM pool derived from oil and less-efficient coal plants.

5/ Between April and June, the construction of the Susquehanna units 1 and 2 have been delayed 10 months and 7 months, respectively, resulting in the NRC's revising the issuance date of an operating license (OL). For Susquehanna 2, the OL delay no longer is anticipated.

6/ Delays for these completed units prior to 4/81 and 6/81 are not included.

Table VIII.2

Estimated Direct Costs of Operating License Delays for Nuclear Units

	1981 Based on Company Data				Based on Independent Staff Analysis			
Unit	Replacement 1/ Power Costs $ Millions/Month		Total 2/ Cost $ Millions		Replacement 7/ Power Costs $ Millions/Month		Total 9/ Cost $ Millions	
	Apr (1)	Jun (2)	Apr (3)	Jun (4)	Apr (5)	Jun (6)	Apr (7)	Jun (8)
Comanche Peak 1	15.0	18.5	210	185	14.5 8/	14.5 8/	203	145
Diablo Canyon 1	31.3 3/	26.8 3/	344	214	30.1	30.1	331	241
Diablo Canyon 2	31.3 3/	28.7 3/	157	86	30.7	30.7	154	92
McGuire 1	6.0 5/	6.9 5/	54	7	5.5	5.5	50	6
Salem 2	23.0	10/	23	0	14.3	-0-	14	0
San Onofre 2	36.0	36.0 6/	387	288	29.6	29.6	296	237
Shoreham 1	30.0	10/	150	0	20.8 8/	10/	0	0
Summer 1	11.5	12.7	115	25	8.5	8.5	85	17
Susquehanna 1	25.0 4/	25.0 4/	425	50	13.5	13.5	230	27
Susquehanna 2	25.0 4/	10/	50	0	13.5	10/	27	0
Waterford 3	27.4	27.4	82	27	19.3 8/	19.3 8/	58	19
Zimmer 1	29.5 7/	8.6	236	52	4.6 8/	4.6 8/	37	28
Total (New units)	-	-	2233	934	-	-	1589	812
TMI 1	17.0	17.0	119	85	14.0	14.0	98	70
Total (including TMI 1)	-	-	2352	1019	-	-	1687	882

1/ Cost of replacement power minus fuel and operating costs of nuclear units.

2/ Derived by multiplying monthly replacement power costs (column 1) by the total months of delay (Table IX.1, columns 6 and 7).

3/ Cost of fuel for 1981 estimated by utility.

4/ Includes fuel-carrying charges.

5/ Does not include other abnormal costs of $2.5 million.

6/ Does not include other abnormal costs of $2.7 million.

7/ Cost of replacement power minus nuclear fuel costs of 6 mills/kWh. Estimates do not include capacity charges which may be incurred if power is purchased from other systems.

8/ Most of delay occurs in 1982; therefore, fuel costs are based on 1982 estimates.

9/ Derived by multiplying monthly replacement power costs (column 5) by total months of delay (Table IX.1, columns 6 and 7).

10/ Not estimated, because no delay was projected

Table VIII.3

Key Assumptions in Staff Estimates of Cost of Nuclear Plant Delays

Unit	Replacement Fuel Mix		Replacement Fuel Price[1] $/Million BTU		Heat Rate of Replacement Fuel[1] - BTU/kWh -	
Comanche Peak 1	Gas	(100%)	Gas	3.19[2]	Gas	10,911
Diablo Canyon 1	Oil	(100%)	Oil	6.50	Oil	10,678
Diablo Canyon 2	Oil	(100%)	Oil	6.50	Oil	10,678
McGuire 1	Coal Nuclear	(89.5%) (10.5%)	Coal	1.89	Coal	9,488
Salem 2	Coal Oil	(50%) (50%)	Coal Oil	1.67 5.84	Coal Oil	10,083 11,240
San Onofre 2	Oil	(100%)	Oil	6.71	Oil	10,035
Shoreham 1	Oil	(100%)	Oil	5.94	Oil	10,389
Summer 1	Coal Oil	(81%) (19%)	Coal Oil	1.71 7.26	Coal Oil	10,001 9,944
Susquehanna 1	Coal Oil	(50%) (50%)	Coal Oil	1.67 5.84	Coal Oil	10,083 11,240
Susquehanna 2	Coal Oil	(50%) (50%)	Coal Oil	1.67 5.84	Coal Oil	10,083 11,240
Waterford 3	Oil	(100%)	Oil	3.91[2]	Oil	11,223
Zimmer 1	Coal	(100%)	Coal	1.79[2]	Coal	10,567
TMI 1	Coal Oil	(50%) (50%)	Coal Oil	1.67 5.84	Coal Oil	10,083 11,240

1/ Source: U.S. Department of Energy, Energy Information Administration, Form FPC-423 Report for April, 1980. DOE/EIA-0173 ('80).
2/ Prices are projections for 1982; all other prices are on a 1981 basis.

[redacted]

References

1. The 60% capacity factor assumption was derived from a Staff analysis of nuclear plants which were granted operating licenses during the period 1976 through 1979.
2. Load projections were obtained from the U.S. Department of Energy Form ERA-411 and utility submissions to state utility commissions.
3. Generating capacity data were obtained from the Reliability Council reports on U.S. Department of Energy Form ERA-411.
4. Power generation data were obtained from Utility System reports on U.S. Department of Energy FPC Form 4.
5. The nuclear fuel price was obtained from the U.S. Department of Energy's Annual Report to Congress 1980.

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CHAPTER IX

Light Load System Studies

One of the "tools" used in the planning and operation of an electric power system is the "load flow study." A load flow study is a "snapshot" of an electric power system that shows, for specified conditions of load and generator outputs, the power flows on each transmission line, the voltage level at each bus, and the phase angle of each voltage; line losses can also be obtained from the study. The study results are obtained by means of mathematical operations on a set of equations that describe certain specified electrical features of the system. A change in the specified features requires that a new "solution" to the set of equations be obtained. For instance, if a change is made in the transmission lines considered to be in service, a new study must be made. Or, if the specified output of a generator is changed (or a generator is taken out of service) a new study must be made. Again, if the specified loads on the system are changed, a new study must be made to find how the power flows in the lines and how the various bus voltages and angles have changed. By making a number of studies, changing the generators in service, their specified loading, the lines in service and the customer load levels, system planners and operators can determine how the system will respond to a range of different conditions. Information obtained from the load flow studies indicates which transmission lines may become overloaded under different conditions, which lines are lightly loaded (and therefore may have spare transmission capacity), which busses are likely to have voltages outside the desired range (low voltage or high voltage), and which generators may be operating at undesirable reactive power levels. Analysis of the results of load flow studies may indicate the need for new (or up-graded) transmission lines, new interconnections, additional generating units or the need for other system facilities. The studies also provide information useful to operating personnel in the development of procedures for responding to emergencies.

Studies made under conditions of heavy loading (such as occur during the winter and summer peak periods on many systems) show how the system responds when highly stressed. But the system may exhibit undesirable characteristics even under light load conditions. Those characteristics may not occur, or may not be obvious, under heavy load conditions. Therefore it is advisable to perform studies of a system under "light load" conditions, where total system load is on the order of 40% to 60% of the system's peak load. Among the characteristics found through light load studies are the magnitudes of overvoltages (which do not occur under conditions of heavy loading) and their impact on system equipment and stability of operation. Even during the seasonal peak periods the system may experience light loading during the off-peak hours. And, of course, light loads occur during the "valley" periods of the year (Spring and Fall on many systems). As a result of these studies operating procedures can be developed and evaluated for responding to high voltage problems and to examine various dispatching arrangements to promote economical, stable operation. A summary of the Reliability Council statements in Item 6B (Light Load System Analysis) of the ERA-411 Reports is given below.

ECAR

The following systems in ECAR conducted studies to investigate voltage and reactive power conditions and to evaluate alternative operating procedures:

> Allegheny Power System (APS) participated in a joint VEPCO - APS - PJM 1/ 1982 summer voltage and reactive power study. The light load portion of the study examined a load level that was 40% of the 1982 summer peak. APS also conducted a study for 1986 to examine the system conditions when the Bath County Project is in the pumping mode. At the time of this report, APS was conducting a joint study with VEPCO to determine the operation of Bath County including the off-peak pumping mode.

1/ This is a three-region study. Virginia Electric and Power Co. (VEPCO) is in Region 12, APS is in Region 1, and the Pennsylvania - New Jersey - Maryland Interconnection (PJM) is in Region 5.

American Electric Power System (AEP) conducted a study to assess the expected system performance during the 1980 4th-of-July weekend in order to evaluate the alternative operating procedures which could be utilized to alleviate high voltage conditions in the area of the Indiana & Michigan Electric Co. The study assumed a load level of 53% of the 1979-1980 winter peak. Various dispatch conditions were considered to determine the impact of a sudden loss of regulating capacity in the study area.

Consumers Power Company, as a general practice, develops and runs selected load flow cases at load levels below 50% of peak load.

Detroit Edison Co. conducted a study to determine operating problems which could occur due to the new Belle River Units 1 and 2 and the Enrico Fermi 2 nuclear unit at full load operation. The period studied was 1982-89 period, at 45% of summer peak load level, having no transactions with neighboring utilities. The results of the study showed that acceptable voltage levels can be maintained by utilizing the available reactive supply.

Ohio Valley Electric Corporation reviewed two load flow base case models of the interconnected transmission system for the light load period during 1980. Bus voltages and line loadings were acceptable.

Various studies were being conducted at the time of filing of the ERA-411 Report by Public Service Co. of Indiana (PSI) to determine system performance during holiday weekends and at minimum peak load levels (35% to 50% of summer peak) during the Spring and Summer of 1988. The purpose of these studies was to determine the severity of steady state overvoltage conditions, the adequacy of reactive power compensation on the 765 KV system associated with Marble Hill and solutions to possible overvoltage conditions. Another study was conducted by PSI for Spring of 1980 at 38% of summer peak load level to determine the impact, of tap changes on various transformers, on reactive power flow and voltage levels.

ERCOT

One study was conducted for January through February of 1981 at 47% of summer peak load. Another study was conducted at 48% of peak load for October through November of 1981, and two studies were conducted for 1982-83 and 1984-85 winters at 41% peak. No significant undesirable results were observed.

MAAC

PJM conducted studies at 50% peak load level for 1980 summer and 1980-81 winter under economic dispatch conditions. Both studies indicated bulk power voltage was satisfactory under normal and contingency conditions.

In a VEPCO - APS - PJM voltage and reactive study for the 1980 summer at 40% of peak load level under economic dispatch conditions, it was determined that availability of baseload generation is an important element in voltage control at the interfaces of these systems. A similar study was being conducted for the 1984 summer during the filing of the ERA-411 Report.

MAIN

One study was conducted by MAIN for the Spring of 1978 at 32% of summer peak load level with "must run"[1] units on and the remaining units dispatched economically. The result of this study showed no significant reliability problems. Union Electric company conducted two studies for the Fall of 1979 and the Spring of 1980 at 60% and 56% of summer peak load levels respectively, under economic dispatch conditions, with maintenance outages taken into consideration. The results of these studies indicated no significant voltage or loading problems.

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[1] "Must run" units are those that--after being brought on line ("committed")--are kept in operation for economic reasons, or because technical system operating reasons militate against their being taken "off the line."

[redacted]

Commonwealth Edison Company conducted a study for the Spring/Fall of 1981 at 35% summer peak load level under economic dispatch. All voltage levels were acceptable.

MARCA

An Iowa Generation and Transmission Task Force conducted studies for the 1981, 1984, and 1985 summers at load levels of 60% to 100% of peak load under economic dispatch. System performance was shown to be satisfactory at 70% to 80% load levels. It was determined that power factors should be maintained at 98% to 100% at 100% load.

Northern States Power Co. will conduct two studies for 1984 and 1985 summer at 70% of peak load levels.

Western Area Power Administration (WAPA) conducted two studies for 1982 and 1990 summer at 70% of peak load level. No significant problems were encountered.

NPCC

The New England System conducted 10 studies under economic, actual, and worst case dispatch conditions at load levels of 34% through 55% of winter peak load levels for 1979, 1985, 1986, and 1990 summers; and 1978-79, 1979-1980, 1982-83, 1983-84, and 1985-86, winters. Following is a summary of the significant results of those studies:

1 - Stability Operating Guides were developed according to NPCC & NEPOOL criteria.

2 - Relay settings were reviewed.

3 - NEPOOL/NYPP Stability Transfer limits were determined.

4 - Investigated February 10, 1980, System Oscillations.

5 - Determined adjustment factors for critical interface flows for system operators.

6 - It was determined that the future Stony Brook generating station will not degrade system reliability.

7 - It was determined that the future Seabrook generating station and related transmission additions will not degrade system reliability.

New York Power Pool conducted three studies for the winter of 1979, the summer of 1979, and the summer of 1980 at 54%, 41%, and 61% of summer peak load levels, respectively, under economic dispatch conditions. Stability limits were determined for power transfers between the following areas:

NEPOOL/NYPP
West Central
Moses South, Central East, Total East,
Upper New York - Con Ed

SERC

Two studies to be used as base cases for stability analysis were conducted by the Florida Region for the 1983 and 1984 summers at 40% of peak load level, under Regional economic dispatch.

One base case economic dispatch study was conducted by the Southern Region for Spring of 1984 at 35% of summer peak load level, with conventional hydro off-line and pumped storage units in pumping mode. Results of this study were not reported.

One base case economic dispatch study was conducted by TVA for the Spring of 1984 with conventional hydro off-line and pumped storage units in pumping mode.

One base case study was conducted by VACAR for the Spring of 1984 at 35% of summer peak load level with conventional hydro off-line and pumped storage units in pumping mode.

SPP

Southwestern Electric Power Co., conducted 2 studies for 1982 at 54% and 46% summer peak load levels, three studies for winter of 1980-81 at 63%, 65%, and 56% summer peak load levels, five studies for April of 1984 at 35% summer peak load level. No major problems were discovered.

Empire District Electric Company conducted 4 studies for 1980, 1981, and 1984, for off-peak periods. No major problems were discovered.

Public Service Company of Oklahoma conducted three studies for October 1981 and 1982 and one study for January of 1984 at 59%, 63%, and 65% summer peak load levels with no major problems indicated.

Kansas City Power and Light Co., conducted one base load economic dispatch study for 1980-81 winter at 27.3% peak load level.

Oklahoma Gas and Electric conducted one study for October 1981 (off peak) at 60% summer peak load level.

WSCC

One study was conducted for 1980 summer at 55% of the summer peak with maximum hydro and maximum NE-SE eastern coal generation transfers. Results that were not in compliance with the WSCC Reliability Criteria for System Design were resolved by the affected member systems.

Two studies were conducted for 1980 and 1984 with 55% and 56% of summer load levels with Northwest and California hydro at low levels and heavy East to West transfers of Eastern coal generation. The results conducted indicate compliance with the WSCC Reliability Criteria for System Design.

One study was conducted for 1981 summer with Northwest hydro at high limit and heavy NE-SE transfers of Eastern WSCC coal generation. The study was continuing at the time of filing of the ERA-411 Report. This study has indicated the necessity for addition of a boundary area generator tripping scheme.

One study was conducted for 1981 summer at 42% of winter peak load, with the same dispatch conditions as those described above. The addition of the Big Eddy 500/230 KV transformer will become necessary when the DC line is uprated to 1000 KV.

One study was conducted for 1981 summer at 42% of winter peak load level, under the same dispatch conditions as those described above. Fixed series compensation levels for the AC Pacific Intertie were established using the results of this study.

One study was conducted for 1981 summer at 42% of winter peak load level, under the dispatch conditions as those described above. The study showed the need for replacement of underrated breakers at Valahalla.

One study was conducted for 1981 summer at 42% of winter peak load level under the same dispatch conditions as those described above. This study was in progress at the time of filing the ERA-411 Report. The portion of the study completed indicated that generator tripping equal to AC intertie scheduled flow may cause NE-SE separation but the system stability will be maintained if no generators are tripped.

One study was conducted for 1980 summer at 38% of winter peak load level. Another study was conducted for 1981 summer at 38% of winter peak load. Various studies were carried out for 1984 summer at 42% of winter peak load level with Northwest and California hydro at low level and heavy East to West transfers of Eastern coal generation.

The results of these studies are listed below:

1980 Summer - Verified adequacy of existing load tripping/load scheduling program.

1981 Summer - Studies were continuing at the time of filing of the ERA-411 Report and results indicate possible need to reduce schedules of East to West transfers for open loop conditions.

1984 Summer - Results indicate that delay of the Bell-Garrison 500 KV line, and loss of the Garrison 500/230 KV transformer, will not cause instability within the Northwest if followed by tripping of a Colstrip unit. An attempt was made to identify several system additions that would control or reduce clockwise loop flow.

Two studies were conducted for 1980-81 winter at 50% of summer peak load level, one study was conducted for 1982-83 winter at 55% of summer peak load level and one study was conducted for 1984-85 winter at 52% of summer peak load level with maximum power transfer from the Jim Bridger Plant and hydro scheduled for maximum transfer to West.

The results of these studies are shown below:

1980-81 Winter Studies - The Bridger Plant must be kept below 1600 MW generation for acceptable system performance for a single contingency outage. The results of further studies will be used to determine transfer capability during open loop operation.

1982-83 Winter Study - This study was continuing at the time of filing of the ERA-411 Report. The results will be used to determine transfer capability, remedial actions, and series capacitor settings.

1984-85 Winter Study - This study was continuing at the time of filing of the ERA-411 Report. The results will be used to determine transfer capability, and series capacitor settings within Idaho Power Co.

One study was conducted for 1984 Summer at 60% of summer peak load level, with minimum hydro and Eastern Montana thermal plants fully loaded. This study was in progress at the time of filing of the ERA-411 Report. The results indicate that during high load periods, reactive power requirements are maximum and stability problems are aggravated.

Two studies were conducted for 1980 and 1984 Autumn at 52% of Summer peak load level with gas and oil units at minimum or off line. No significant problems were indicated.

Chapter X
TRANSMISSION

Transmission circuits perform the task of physically integrating the output of generating plants and the requirements of customers for electricity. This function is performed by providing pathways for the flow of electric energy between generating units, between generating units and load centers (substations for subdividing bulk quantities of electricity) and between utilities. The flow of power over any line that is part of an electrical network depends not only on the physical characteristics of the line but also on the operating conditions of the entire system (loads, output of generating plants, phase angles between generating plants). Simplistic analysis based on the so-called "carrying capacity" of a line at a given voltage level does not provide results accurate enough for system planning decisions. Transmission construction plans are based on numerous studies which in many instances involve more than one utility system. The adequacy of the transmission network within a Council area depends on a number of factors. Among those factors are the voltage levels and lengths of the lines. Table X.1 is a summary of major transmission line construction projected within the Reliability Councils for 1981-1990. The data are taken from Item 5B of each Council's April 1, 1981 ERA-411 Report and comprise the bulk power transmission lines considered by the reporting utilities to be significant for interconnected operation.

Table X.1

PROJECTED BULK POWER TRANSMISSION LINES 1981-1990
MILES OF LINE AT EACH VOLTAGE LEVEL
As Reported April 1, 1981 in the Reliability Council ERA-411 Reports

COUNCIL	230 Kv	345 Kv	500 Kv	765 Kv	Other	Total
ECAR	214.7	1,212.4	282.0	1,126.0	-0-	2,835.1
MAAC	787.6	10.4	576.1	-0-	36.0	1,410.1
MAIN	-0-	816.0	-0-	-0-	-0-	816.0
MARCA	978.4	2,248.6	670.0	-0-	2,160.9	6,057.9
NPCC	0.4	584.5	-0-	-0-	443.4	1,028.3
SERC	3,185.9	-0-	2,641.9	2.0	37.3	5,867.1
SPP	517.0	2,850.0	1,100.0	-0-	199.9	4,666.9
Subtotal	5,684.0	7,721.9	5,270.0	1,128.0	2,877.5	22,681.4
WSCC	5,839	5,328	7,267	-0-	1,727	20,161.0
ERCOT	-0-	3,342.0	-0-	-0-	-0-	3,342.0
U.S. Total	11,523	16,391.9	12,537	1,128	4,604.5	46,184.4

CHAPTER XI
INTER-REGIONAL CAPACITY TRANSFERS

Transfers of capacity are a frequent and normal occurrence among utility systems. Transfers may be scheduled long in advance for a long-term period, or may be scheduled shortly before they are to take place. Transfers may be "firm sales", meaning that the seller agrees to provide the reserve capacity needed to assure availability of the capacity he is selling (even under adverse circumstances) or they may be "non-firm sales". In the case of a "non-firm sale" there is no commitment on the part of the seller to provide reserves to back up the sale. In Item 2C of the ERA-411 Reports each Council provides a ten-year summary of scheduled exports and imports of capacity among Council areas. Some Councils have, in addition, shown inter-regional or inter-utility scheduled transfers. Table XI.1 summarizes all the Item 2C information regarding exports from one Council area to another. In all cases, the transfer agreements are between individual utilities or pools. The Councils are involved only to the extent of providing a forum for facilitating discussions of transfer possibilities. For the purposes of Item 2C, a scheduled export is one which takes place at the time of peak load on the exporting system. The peak load of the Council in which the exporting system is located may occur at a different time. Further, the peak load of the utility receiving the exported power may occur at a different time. The tables for the later years show few such exchanges. This is not because the systems do not anticipate such exchanges but rather because many of these types of arrangements are made as systems near-term needs can be ascertained.

Table XI.1
Scheduled Exports of Capacity in Megawatts From Reliability Council Areas As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1981

Exporting Council Area**	To Council Area									Export Total
	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	
ECAR			300	624			300			1224
ERCOT										0
MAAC										0
MAIN										0
MARCA				3					54	57
NPCC	23									23
SERC				260				700		960
SPP		5		53						58
WSCC										0
Total Import	23	5	300	940	0	0	300	700	54	2322

Winter 1981-82

Exporting Council Area**	To Council Area									Export Total
	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	
ECAR				624						624
ERCOT										0
MAAC										0
MAIN							260			260
MARCA				3					54	57*
NPCC	23									23
SERC	300									300
SPP		5					700			705
WSCC										0
Total Import	323	5	0	627	0	0	960	0	54	1969

* In addition MARCA shows a scheduled export of 300 MW to the Manitoba (Canada) Hydro-Electric Board.

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts From Reliability Council Areas As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1982

Exporting Council Area**	To Council Area: ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR				624			300			924
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				260				700		960
SPP		5		56						61
WSCC										0
Total Import	23	5	0	943	0	0	300	700	0	1971

Winter 1982-83

Exporting Council Area**	To Council Area: ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR				624						624
ERCOT										0
MAAC										0
MAIN							260			260
MARCA				3						3*
NPCC	23									23
SERC	300									300
SPP		5					700			705
WSCC										0
Total Import	323	5	0	627	0	0	960	0	0	1915

* In addition MARCA shows a scheduled export of 300 MW to the Manitoba (Canada) Hydro-Electric Board

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts
From Reliability Council Areas
As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1983

Exporting Council Area**	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
	To Council Area									
ECAR				624			300			924
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				260				700		960
SPP		15		59						74
WSCC										0
Total Import	23	15		946	0	0	300	700	0	1984

Winter 1983-84

Exporting Council Area**	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
	To Council Area									
ECAR				312						312
ERCOT										0
MAAC										0
MAIN							260			260
MARCA				3						3*
NPCC	23									23
SERC	300									300
SPP		15					200			215
WSCC										0
Total Import	323	15	0	315	0	0	460	0	0	1113

* In addition, MARCA shows a scheduled export of 300 MW to the Manitoba (Canada) Hydro-Electric Board.

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

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Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts
From Reliability Council Areas
As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1984

Exporting Council Area**	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
	To Council Area									
ECAR				312			300			612
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				260				200		460
SPP		10		62						72
WSCC										0
Total Import	23	10	0	637	0	0	300	200	0	1170

Winter 1984-85

Exporting Council Area**	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
	To Council Area									
ECAR				312						312
ERCOT										0
MAAC										0
MAIN							35			35
MARCA				3						3*
NPCC	23									23
SERC	300									300
SPP		10					200			210
WSCC										0
Total Import	323	10	0	325	0	0	235	0	0	883

* In addition MARCA shows a scheduled export of 300 MW to the Mantitoba (Canada) Hydro - Electric Board.

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts From Reliability Council Areas As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1985

Exporting Council Area**	To Council Area ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR				312			300			612
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				35				200		235
SPP		72		65						137
WSCC										0
Total Import	23	72	0	415	0	0	300	200	0	1010

Winter 1985-86

Exporting Council Area**	To Council Area ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR				312						312
ERCOT										0
MAAC										0
MAIN							35			35
MARCA				3						3*
NPCC	23									23
SERC	300									300
SPP		72					200			272
WSCC										0
Total Import	323	72	0	315	0	0	235	0	0	945

* In addition MARCA shows a scheduled export of 300 MW to the Manitoba (Canada) Hydro-Electric Board.

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts
From Reliability Council Areas
As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1986

Exporting Council Area**	To Council Area									Export Total
	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	
ECAR				312						312
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				35				200		235
SPP		27		68						95
WSCC										0
Total Import	23	27	0	418	0	0	0	200	0	668

Winter 1986-87

Exporting Council Area**	To Council Area									Export Total
	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	
ECAR			312							312
ERCOT										0
MAAC										0
MAIN							35			35
MARCA				3						3*
NPCC	23									23
SERC										0
SPP		27					200			227
WSCC										0
Total Import	23	27	312	3	0	0	235	0	0	600

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* In addition MARCA shows scheduled exports of 300 MW to the Manitoba (Canada) Hydro-Electric Board and 100 MW to Saskatchewan (Canada).

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts From Reliability Council Areas As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1987

Exporting Council Area**	To Council Area: ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR				312						312
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				35				200		235
SPP				71						71
WSCC										0
Total Import	23	0	0	421	0	0	0	200	0	644

Winter 1987-88

Exporting Council Area**	To Council Area: ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR				312						312
ERCOT										0
MAAC										0
MAIN							35			35
MARCA				3						3*
NPCC	23									23
SERC										0
SPP							200			200
WSCC										0
Total Import	23	0	0	315	0	0	235	0	0	573

* In addition MARCA shows scheduled exports of 600 MW to the Manitoba (Canada) Hydro - Electric Board and 100 MW to Saskatchewan (Canada).

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

[redacted]

Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts From Reliability Council Areas As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1988

Exporting Council Area**	To Council Area ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR				312						312
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				35				200		235
SPP				74						74
WSCC										0
Total Import	23	0	0	424	0	0	0	200	0	647

Winter 1988-89

Exporting Council Area**	To Council Area ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR										0
ERCOT										0
MAAC										0
MAIN							35			35
MARCA				3						3*
NPCC	23									23
SERC										0
SPP							200			200
WSCC										0
Total Import	23	0	0	3	0	0	235	0	0	261

* In addition MARCA shows scheduled exports of 600 MW to the Manitoba (Canada) Hydro-Electric Board and 100 MW to Saskatchewan (Canada).

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts From Reliability Council Areas As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1989

Exporting Council Area**	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
	To Council Area									
ECAR										0
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				35				200		235
SPP		116		77						193
WSCC										0
Total Import	23	116	0	115	0	0	0	200		454

Winter 1989-90

Exporting Council Area**	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
	To Council Area									
ECAR										0
ERCOT										0
MAAC										0
MAIN							35			35
MARCA				3						3*
NPCC	23									23
SERC										0
SPP							200			200
WSCC										0
Total Import	23	0	0	3	0	0	235	0		261

* In addition, MARCA shows scheduled exports of 600 MW to the Manitoba (Canada) Hydro-Electric Board and 100 MW to Saskatchewan (Canada).

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

Table XI.1 (continued)
Scheduled Exports of Capacity in Megawatts From Reliability Council Areas As Reported April 1, 1981 in ERA-411 Item 2C

Summer 1990

Exporting Council Area**	To Council Area									
	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR										0
ERCOT										0
MAAC										0
MAIN										0
MARCA				3						3
NPCC	23									23
SERC				35				200		235
SPP		251		80						331
WSCC										0
Total Import	23	251	0	118	0	0	0	200	0	592

Winter 1990-91

Exporting Council Area**	To Council Area									
	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SPP	WSCC	Export Total
ECAR										0
ERCOT										0
MAAC										0
MAIN							35			35
MARCA				3						3*
NPCC	23									23
SERC										0
SPP		251					200			451
WSCC										0
Total Import	23	251	0	3	0	0	235	0	0	512

* In addition, MARCA shows scheduled exports of 600 MW to the Manitoba (Canada) Hydro-Electric Board and 100 MW to Saskatchewan (Canada).

** The export of capacity is scheduled for the time of peak demand in the exporting system, but may also take place at other times.

CHAPTER XII

Interruptible Power

Electric power is usually supplied by utilities with the understanding that the utility will exercise its best efforts to maintain continuity of service. One way in which a utility attempts to maintain service continuity is to install sufficient generating capacity to meet all demands that can reasonably be expected. Since generating capacity is expensive, a utility attempts to minimize the amount of capacity installed, without jeopardizing its ability to supply its customers. In some instances, a utility may find that it can under normal circumstances supply power that it cannot supply under abnormal circumstances. A system that is heavily hydroelectric, for instance, may find that under drought conditions its ability to provide capacity and energy is severely curtailed. A utility that wishes to make provision for possible service curtailments may offer interruptible power to some customers (usually industrial customers). This classification of power is supplied under a contract that states in detail the conditions under which the supply to the purchaser may be curtailed or interrupted by the utility. Table XII.1 is a summary of the interruptibility conditions reported in Item 7C of the April 1, 1981, Reliability Council reports to the Department of Energy under ERA-411. In return for agreeing to possible curtailment of supply, the customer receives a lower rate than would be required for "firm" power. The customer, of course, must evaluate the balance between the lower cost of interruptible power and the economic or other penalties his enterprise may suffer due to implementation of the interruptibility conditions. The utility, for its part, evaluates the economic or operational advantage of being able to curtail part of its load under conditions of necessity, within the constraints of its agreement.

Table XII.1 is not intended to show all the features of interruptible power contracts in the U.S., nor even to list all the constraints reported by the Councils. The purpose of the table is to indicate the range of provisions currently in use. A further purpose of the table is to show that, while in some instances interruptible power may be considered as equivalent to peak load reserve capacity, this equivalence may not always be true. It is evident from Table XII.1 that constraints on interruptibility may preclude the use of interruptible power for reserve purposes at peak load (or other) times.

Table XII.1.1

Interruptible Load Constraints

As Reported by the Regional Reliability Councils

In Item 7C of ERA-411 dated April 1, 1981

Electric Reliability Council	Load That Can Be Interrupted (MW)	Notice Required Before Interruption (Minutes)	Other Conditions
ECAR	No interruptible load reported	-	-
ERCOT	97	As much as possible; none in emergency	-
	336	None	Limits load served to 8000 hours per year; summer peak periods are excluded.

[redacted]

Table XII.1.2

Electric Reliability Council	Load That Can Be Interrupted (MW)	Notice Required Before Interruption (Minutes)	Other Conditions
MAAC	3	120	Customer will curtail his maximum demand by at least 2 MW.
	34	30 or more	Interruptions shall not exceed 20, nor exceed a total of 150 hours per year.
	90	30	Interruptions may be made only between 8 am - 9 am EST or 9 am - 10 pm EDST
	130	120	-
MAIN	0-35	60 - Normal Condition	-
	1	60	-
	3.5	None	Interruptions are limited to one occurrence of 12 hours per day, not to exceed 30 occasions or 300 hours between 6/1 and 5/31.
	25 1/	-	Unlimited interruptions during summer peak hours.
	30	None in emergency	-
	30 - 100	30	-
	31 1/	-	Limited to 1,560 hours of interruptions per year.
	36 2/	-	Limited to 150 hours of interruptions per year.
	45 1/	-	Limited to 60 interruptions for maximum of 200 hours per year, each interruption limited to 12 hours.
	70 1/	-	Unlimited interruptions.
MARCA	2 3/	None	-
	3 4/	60	-
	4 4/	-	Interruption up to 90%
	5 3/	120	-
	8 3/	10	-
	18 3/	-	-
	20 3/	120	-
	67 3/	60	-
	90 4/	-	-

[redacted]

Table XII.1.3

Electric Reliability Council	Load That Can Be Interrupted (MW)	Notice Required Before Interruption (Minutes)	Other Conditions
NPCC	2	1080	Temperature 90° or above, maximum number of interruptions is 10 per year
	4	10	No limit to hours, or energy interrupted
	6	10	Limited as to hours, or energy which may be interrupted
	8	10	No limit to hours or energy interrupted
	10	30	Limited as to hours, or energy which may be interrupted
	13	10	No limit to hours, or energy interrupted
	15	30	Between 5/15 - 10/15 maximum number of interruptions is 17, maximum duration is 8 hours
	16	10	Limited as to hours, or energy which may be interrupted
	155	-	-
SERC	25	150	-
	40	150	-
	100		-
	203 4/	30	-
	211.3	240; 15 in an emergency	Interruptions limited 600 hours per year, 40 hours per week, 8 hours per day, 2 interruptions per day
	225 3/	30	-
	250	30 - 40 MW; 60 - 210 MW	-
	848	5	For 5% of customers no more than 2 curtailments per day; for the 2 curtailments, the total time reduced during a calendar day is not to exceed 12 hours; and total hours reduced for a calendar week must not exceed 60; for any 12-month period, the customer may be curtailed no more than 800 hours. For 3% of customers same restrictions as above apply except total hours reduced during a week must not exceed 48, and for any 12-month period, the customer may be curtailed no more than 600 hours.

Table XII.1.4

Electric Reliability Council	Load That Can Be Interrupted (MW)	Notice Required Before Interruption (Minutes)	Other Conditions
SPP	2.0	120 - 360	Limited as to number of hours of interruptions per year.
	2.5	60 - 120	Same as above
	3.0	480 - 720	Same as above
	3.5	60 - 240	Same as above
	12	30 or less	-
	13	30	-
	15	None in emergency emergency	-
	25	-	-
	100	240 - peak load basis; 480 - economy load basis	Interruptions limited to 8 hours.
WSCC	3	480	-
	10	-	Curtailment can be for 8 hours per day, 6 consecutive days and not to exceed 36 hours in 1 calendar week
	10	120 - emergency	-
	16	None if frequency drops to 59.75 Hz	-
	20	30	-
	25	-	Curtailment can be for 8 hours per day, 6 consecutive days and not to exceed 36 hours in 1 calendar week
	38.5	30	-
	39	-	-
	48	-	-
	60	None	Interruptions limited to 15 hours hours per week, and 600 hours per year.
	60	-	-
	61.8	10	-
	70	Under 10	Make available 184,000 MWH per contract year.

[redacted]

Table XII.1.5

Electric Reliability Council	Load That Can Be Interrupted (MW)	Notice Required Before Interruption (Minutes)	Other Conditions
WSCC (Cont.)	70	1020	-
	80	-	-
	99	-	-
	112	1440 - Secondary supply	Must make available 50% of secondary demand for any 1 year.
	120	Under 10	300 hours per year of primary interruption allowed.
	150	-	Load can be curtailed totally on any given hour but energy lost cannot exceed 15% annually
	858	None - first 25% of contract demand	The acumulated KWH amount per year is limited to 375 times the contract demand.
	858	As much as possible - 25% of contract demand in addition to first 25% listed above	-
	1074	As much as possible - first 25% of contract demand and 100% of any authorized increases over contract demand	-
	1638	None - 50% of actual load for up to 2 hours	The accumulated KWH amount per year is limited to 50 times the contract demand.
	3650	None	-

1/ Current maximum contract demand. Actual load at any time could be less.
2/ Projected Summer 1981 peak value. Actual interruptible load depends on customer's load at time of interruption.
3/ Summer 1981.
4/ Winter 1981/82.

[redacted]

CHAPTER XIII

Cogeneration

A cogeneration facility is defined in Title II, Sec. 201, of the Public Utility Regulatory Policies Act of 1978 (Public Law 95-617, November 9, 1978) as a facility which produces: "(i) electric energy and (ii) steam or other forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes."

The practice of cogeneration as defined in the Public Utility Regulatory Policies Act (PURPA) has long been known to industry. In the technical literature dealing with industrial plants, a number of articles can be found which report on cogeneration installations, their operation and their costs, as well as on the benefits expected. These installations generally have been made, in the U.S., by industrial organizations, for the purpose of reducing the overall cost of energy (electrical, heat, steam, or other form) to an individual industrial plant, for the purpose of assuring electric power that would be independent of contingencies that might affect central station supply or for other reasons sufficient to the industrial corporation. It has not been the general practice in the U.S. for industrial corporations to consider cogeneration principally as a means of supplying electrical capacity and electric energy to public utilities. In some countries, cogeneration facilities have been operated as adjuncts to public electric supply systems and have also been used to supply steam for public use.

Within the decade of the 1970's, the rising cost of electric service in the U.S. and the realization that energy resources have a finite base, have impelled the public, electric utilities, industry and governmental agencies to seek greater efficiency in the production of energy. This search for efficiency has resulted in various initiatives, among them greatly increased emphasis on cogeneration, especially with regard to cooperation by industry and electric utilities.

A variety of methods, procedures, processes, and design options can be employed to implement the cogeneration concept. Whatever form a specific facility may take, the elements of major interest to an electric utility are the reliability of the capacity and electric energy to be supplied to the utility's system, the effects on utility planning, and the costs involved. In planning its power supply system, an electric utility must have confidence in its ability to operate generating units as necessary to meet customer demand. If a significant portion of a utility's capacity should be vested in cogenerating units, under control of various industrial enterprises and geared primarily to the needs of those enterprises, a utility's ability to meet demand and energy requirements at all times may be impaired. However, utility responsibility to its customers will remain. In view of the possible impact that cogeneration could have on utility planning, each Reliability Council was asked to discuss cogeneration, in its April 1, 1981, ERA-411 Report on long-range coordinated planning, as it affected utility plans for future power supply. By requesting this discussion, Staff hoped to stimulate the thinking of utility planners, obtain a diversity of view points, and provide a basis for further analytic work. A summary of the Council responses is provided below.

ECAR - No response.

ERCOT - No response.

MAAC - In Item 8 (Additional Material for Clarification), it is stated that cogeneration exists to a limited extent and is anticipated to increase. It is also stated that cogeneration is among the activities currently being considered or under way by the MAAC systems.

MAIN - In Item 8, MAIN states that a review of existing systems indicates the effect of cogeneration on existing systems is minimal, and that the effect will not change appreciably in the 1980 decade.

MARCA - No response.

[redacted]

NPCC - No response.

SERC

Florida - No response.

Southern - No response.

TVA - No response.

VACAR - Current indications are that a significant amount of dependable power will not be available from this source over the next few years.

SPP - No response.

WSCC - In Item 3B (Assessment of Adequacy of Power Supply for the first 5 years), WSCC reports that cogeneration sources totalled 305 MW as of January 1, 1981, constituting 0.3% of the total WSCC (including Canada) installed capacity. It is estimated that as of December 31, 1985, the total cogeneration capacity will be 587 MW, or 0.4% of total WSCC (including Canada) installed capacity of 140912 MW.

The foregoing Council statements are general in nature and do not fully indicate the extent of cogeneration activity. With the help of the Argonne National Laboratory, Staff has compiled specific information on projected cogeneration activities that are proceeding under Sections 201 and 210 of PURPA. The purpose of these Sections is to encourage the installation of cogeneration and small power production facilities[1] connected to the interconnected electric utility network. Section 201 of PURPA provided criteria for certification of qualifying cogenerators and small power producers. Facilities which satisfy the requirements of Section 201 are exempted under Section 210 from regulation as utilities and are eligible for energy and capacity payments from utilities to which they supply power. Section 210 provides for the establishment by State Public Utility Commissions and nonregulated utilities of purchase rates for such such power which is required to reflect the utilities' avoided energy and capacity costs.

The Federal Energy Regulatory Commission (FERC) promulgated rules[2] establishing the criteria and procedures for obtaining qualifying status on March 13, 1980. On February 19, 1980, the FERC promulgated rules for implementation of Section 210 by the state commissions and nonregulated utilities. These rules directed establishment by March 20, 1981, of appropriate rates and procedures. By that date, some states and utilities had already completed their hearings and had reported established purchase rates to FERC, but others were still conducting hearings or developing their implementation plans. Figure XIII.1 shows the status, as of May 1981, of rates for purchase of power by utilities from cogenerators and small power producers. Table XIII.1 is a sampling of rates established for state-regulated utilities in several Electric Regions. The table is not a comprehensive compilation, but is only intended to indicate the features of some established rate structures. It is evident that the the rates vary in magnitude and have various conditions attached,

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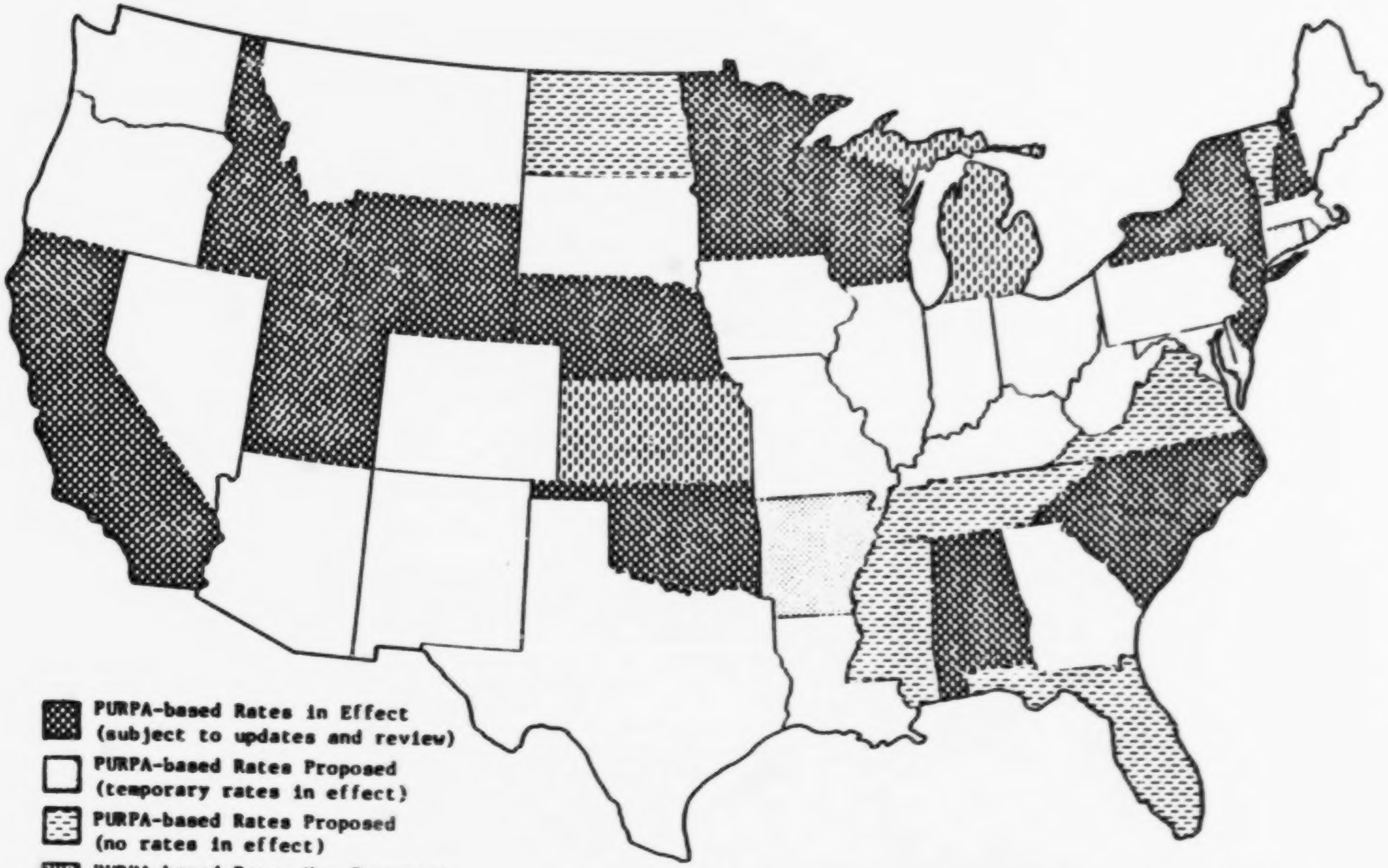
[1] "Small power production facility" is defined in PURPA, Section 201, as a facility which: "(i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, or any combination thereof; and (ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts;" "Commission" refers to the Federal Energy Regulatory Commission.

[2] Final Rule Regarding the Implementation of Section 201 of the Public Utility Regulatory Policies Act of 1978, U.S. Federal Energy Regulatory Commission, Order No. 70 (Docket No. RM 79-54), issued March 13, 1980. Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, U.S. Federal Energy Regulatory Commission, Order No. 69 (Docket No. RM 79-55), issued February 19, 1980.

[redacted]

such a firm and non-firm power; peak, off-peak and intermediate; seasonal constraints. In some instances, capacity payments are made.

Table XIII.2 is a sampling of rates established for non-regulated utilities. Table XIII.3 shows the variety of energy sources proposed in applications for qualifying status under PURPA. Table XIII.4 provides a summary of information concerning applications to FERC for qualifying status. Figure XIII.2 shows the approximate location of the facilities associated with each of the applications listed in Table XIII.4.



▩ PURPA-based Rates in Effect (subject to updates and review)

☐ PURPA-based Rates Proposed (temporary rates in effect)

▤ PURPA-based Rates Proposed (no rates in effect)

▦ PURPA-based Rates Not Proposed (temporary rates in effect)

Status of Rates For Cogeneration and Small Power Production
Under PURPA Section 210
(State-Regulated Utilities)

Figure XIII.1

p. 1 of 4

Table XIII.1
A Sample of Rates for Power Purchased From Qualifying Cogenerating and Small Power Facilities By State Regulated Utilities As of May 1, 1981

Electric Region (State Commission)	Utility (Electric Reliability Council)	Energy Payments (¢/kWh)	Capacity Payments ($/kW-yr)
3 - NEPOOL (Connecticut)	Connecticut Light & Power Co. and Hartford Elec. Light Co. (NPCC)	Firm Power: 6.7; on-peak equals 114.5% of fossil fuel cost 5.4; off-peak equals 90.5% of fossil fuel cost Non-Firm Power: 6.6; on-peak equals 110% of fossil fuel cost 5.2; off-peak equals 86.5% of fossil fuel cost	
4 - NYPP (New York)	Long Island Lighting Co. (NPCC)	3.84-4.15, on-peak 3.53-3.33, intermediate 2.29-2.40, off-peak (depending on level of interconnection)	26.0-27.0, on-peak; 2.5, intermediate; 0, off-peak (depending on level of interconnection)
5-PJM (New Jersey)	Jersey Central Power and Light Co. (MAAC)	Approximate only 6.0-7.5; on-peak 2.0-5.0; off-peak	

Table XIII.1

Electric Region (State Commission)	Utility (Electric Reliability Council)	Energy Payments (¢/kWh)	Capacity Payments ($/kW-yr)
7 - VACAR (North Carolina)	Carolina Light & Power Co. (MAAC)	2.80-5.55; on-peak 2.07-4.04; off-peak	1.49-2.39; summer months 1.29-2.08; non-summer months
8 - MSU/Gulf (Arkansas)	Arkansas Power & Light Co. (SWPP)	Reverse metering currently used	
9 - Southern Co. (Alabama)	Alabama Power Co. (SERC)	2.61; on-peak, June-Oct 1.88; off-peak, June-Oct 2.20; on-peak, Nov-May 1.77; off-peak, Nov-May	
11 - TVA (North Carolina)	Nanthahala Power & Light Co. (SERC)	2.05	2.50
18 - MECS (Michigan)	Statewide purchase rate includes Consumers Power Co. Detroit Edison (ECAR)	2.5	
19 - WUMS (Wisconsin)	Wisconsin Power & Light Co. (MAIN)	4.80; on-peak 1.75; off-peak (includes capacity payments)	

Table XIII.1

Electric Region (State Commission)	Utility (Electric Reliability Council)	Energy Payments (¢/kWh)	Capacity Payments ($/kW-yr)
20 - MARCA (Minnesota)	Northern States Power Co.	Firm Power: 2.06-3.07 increasing with contract legnth 5-25 yrs. TOD metering service: 2.15 on-peak 1.39 off-peak Non-Firm Power: 1.35 Occasional Power: 1.66	
21 - MOKAN (Kansas)	Kansas Power & Light Co. (SWPP)	1.60	
22 - OKLA (Oklahoma)	Statewide rate schedules include OK Gas & Elec. Co. Public Service Co. (SWPP)	.86-3.05 depending on firmness of capacity	

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Table XIII.1

Electric Region (State Commission)	Utility (Electric Reliability Council)	Energy Payments (¢/kWh)	Capacity Payments ($/kW-yr)
24 - RMPA (Wyoming)*	Tri-County Elec. Assoc. (WSCC)	1.07	
25 - NWPP (Idaho)	Idaho Power Co. (WSCC)	Firm-Power: 1.639 Non-Firm Power: 1.41-3.86 (varies each month)	116-318 increasing with contract length 4-35 yrs.
27 - Southern Cal/New (California)	San Diego Gas & Elec.Co. (WSCC)	7.748; without TOD metering 8.457; on-peak 7.174: semi-peak 6.317; off-peak	0-40 depending on availability 10.65 and contract length (1-25 yrs). Incentive capacity payments: $/kW mo. — Capacity factor .00 — 0-14 .70 — 15-49 1.30 — 50-85 2.00 — 85-100
28 - North Cal/New (California)	Pacific Gas & Electric Co. (WSCC)	4.682; on-peak, May-Sep 4.504; partial-peak, May-Sep 3.878; off-peak, May-Sep 4.496; on-peak, Oct-Apr 4.250; partial-peak, Oct-Apr 3.794; off-peak, Oct-Apr	55-81 for dispatchable capacity (increases with length of contract 4-30 yrs); other options available for non-dispatchable capacity.

* NOTE: All of the Wyoming purchase rates are "experimental"

TABLE XIII.2 SAMPLE RATES OF NON-REGULATED SYSTEMS REPORTING DIRECTLY TO FERC FOR POWER PURCHASED FROM QUALIFYING FACILITIES

Electric Region (State Commission)	Utility (Electric Reliability Council)	Energy Payments (¢/kWh)	Capacity Payments ($/kW-yr)	Comments
5 - PJM (Pennsylvania)	Adams Elec. Coop., Gettysburg (MAAC)	2.0 in area of Pa. Elec. 2.1 in area of Met. Edison 0.6 in area of West Penn Power Co. 2.1 in area of Jersey Central Power & Light		For facilities less than 100 kW.
9 - Southern Co. Group (Alabama)	South Alabama Elec. Coop. (SERC)	2.035		
11 - TVA (Tennessee)	Tennessee Valley Authority (SERC)	Standard Rate: 2.792 Time-of-Day Rate: 3.770; on-peak 2.372; off-peak		Purchase rates are for facilities less than 100 kW. Retail rates not available at time of publication.
17 - ILMO (Missouri)	Central Electric Power Coop., Jefferson City (MAIN)	1.415		Limited to facilities less than 100 kW.
25 - NWPP (Washington)	Skmania County, Carson (WSCC)	.413; Sep-Mar .376; Apr-Aug	$1.95/kW-month; Dec-May 7 am-10 pm, Mon-Sat $1.19/kW-month; Jun-Nov 7 am-10 pm; Mon-Sat $0 all other hours	For facilities less than 100 kW.
20 - MARCA (Nebraska)	City of Fairbury (MARCA)	1.68; standard rate Time-of-Day Rate: 3.41 on-peak 1.37 off-peak		Limited to facilities less than 100 kW.

[redacted]

Table XIII.3
Energy Sources Proposed In Applications For Qualifying Status As Cogenerator or Small Power Producer

Fuel Type	Megawatts (existing and proposed)
Hydro	109.53
Natural Gas and Fuel Oil	172.60
Coal	48.00
Wind	76.07
Geothermal	160.00
Gas, Oil, Coal Derivatives	598.48
Biomass/Ag. Waste	54.50
Wood Waste	487.00
Nuclear	19.50
Unidentified	---
Totals	1725.68

TABLE XIII.4 Applications for Status as Qualifying Cogenerator or Small Power Producer under PURPA Section 201

FERC #	Fuel Type	Facility Status	Electrical Generation Capacity	Federal Register Citation	Qualifying Status Granted	Comments
QF80-1	Hydro	Existing	15 MW	Vol. 45, p. 24533 4/10/80	Yes	
QF80-2	Hydro	Existing	3 MW	Vol. 45, p. 42797 6/25/80	Yes	
QF80-7	Hydro	Proposed	2.3 MW	Vol. 45, p. 11206 6/18/80	Yes	
QF80-8	Hydro	Proposed	8.921 MW	Vol. 45, p. 43857 6/30/80	Yes	
QF80-14						
A	Hydro	Existing	900 kW		Self-certifying	
B	Hydro	Existing	1250 kW			
C	Hydro	Existing	1740 kW			
D	Hydro	Existing	1600 kW			
QF80-16	Hydro	Existing and Proposed Additions	22.92 MW	Vol. 45, p. 56136 8/22/80	Yes	
QF80-17	Hydro	Existing and Proposed Additions	20.05 MW	Vol. 45, p. 56156 8/22/80	Yes	4 sites
QF80-21	Hydro	Existing	1.4 MW	Vol. 45, p. 61774 9/17/80	Yes	
QF80-32	Hydro	Existing	18 MW		Self-certifying	

TABLE XIII.4 - Continued

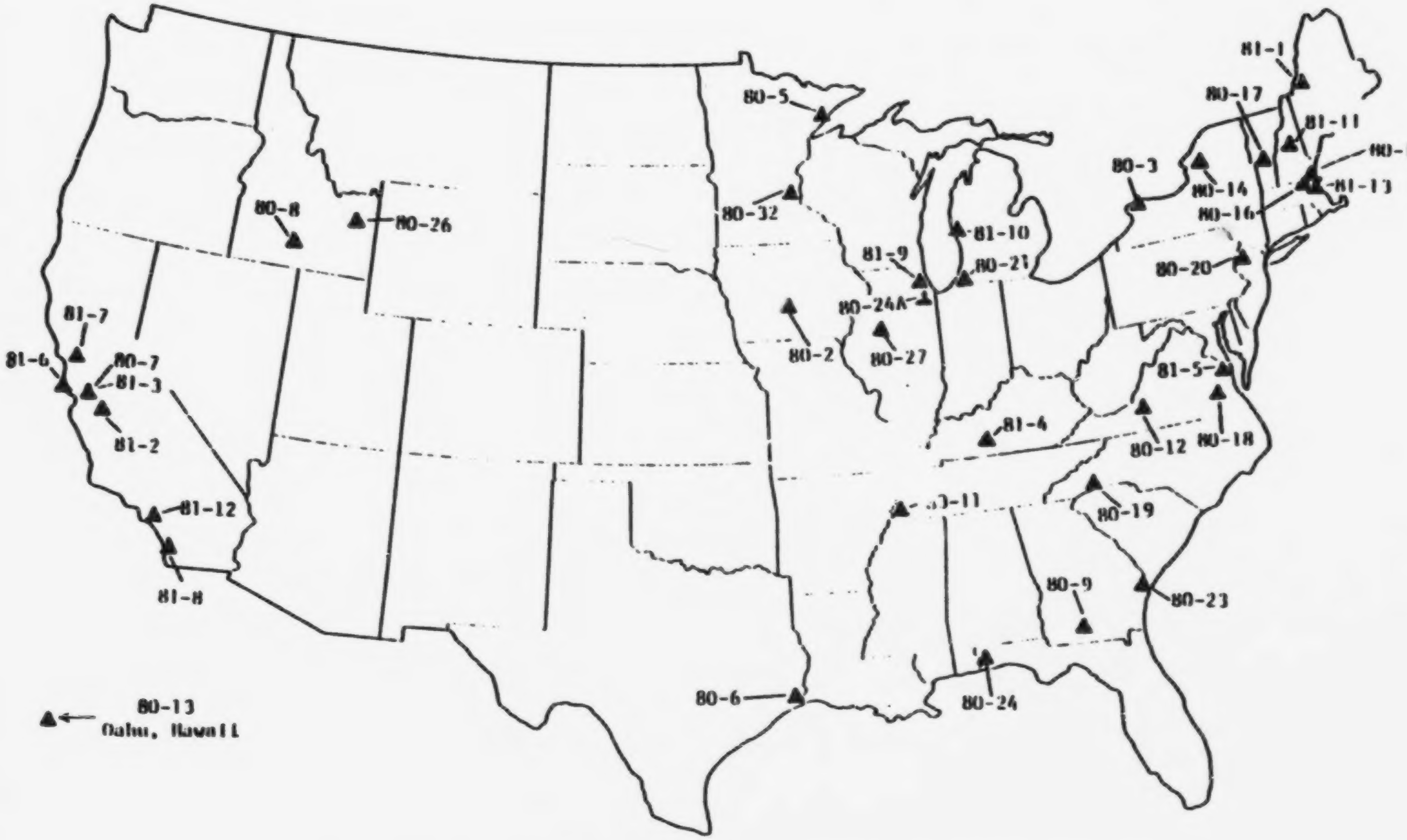
FERC #	Fuel Type	Facility Status	Electrical Generation Capacity	Federal Register Citation	Qualifying Status Granted	Comments
QF81-1						
A	Hydro	Existing	3.65 MW		Self-certifying	
B	Hydro	Existing	6 MW			
QF81-2	Hydro	Proposed	2.8 MW	Vol. 45, p. 72760 11/3/80	Yes	
QF80-3	#6 Fuel Oil	Existing	6.25 MW	Vol. 45, p. 27811 4/24/80	Yes	Topping Cycle
QF80-5	Natural Gas	Existing	127.75 MW		Self-certifying	Topping cycle
QF80-11	Natural Gas and #6 Fuel Oil	Proposed	1 MW	Vol. 45, p. 43849 6/30/80	Yes	Topping Cycle
QF80-24	Gas and #6 Fuel Oil	Existing	16 MW		Self-certifying	Topping cycle
QF80-27	Natural gas & fuel oil	Existing	15 MW	Vol. 45, p. 72764 11/8/80	Yes	Topping cycle
QF81-6	Natural gas and #2 fuel oil as alternative	Proposed	2.6 MW	Vo. 46, p. 6038 1/21/81	Yes	Topping cycle
QF81-8	Natural gas	Existing	1.2 MW	Vol. 46, p. 6042 1/21/81	Yes	Topping cycle
QF81-12	Natural gas and #2 fuel oil as alternate	--	2.8 MW	Vol. 46, p. 12268 2/13/81	Yes	Topping cycle
QF80-18	Coal	Proposed	10 MW		Self-certifying	Topping cycle

TABLE XIII.4 - Continued

FERC #	Fuel Type	Facility Status	Electrical Generation Capacity	Federal Register Citation	Qualifying Status Granted	Comments
QF80-19	Coal (Oil & Gas Alternatives)	Existing	3 MW	Vol. 45, p. 61773 9/17/80	Yes	Topping cycle
QF80-24A	Coal, gas and oil	Existing	12 MW	--	Self-certifying	Topping Cycle
QF81-10	Coal	Existing	23 MW	--	Self-certifying	
QF80-13	Wind	Proposed	76 MW	Vol. 45, p. 49123 7/23/80	Yes	3 clusters of wind machines
QF80-29	Wind	Proposed	8 kW	--	Self-certifying	
QF81-5	Wind	Existing	4 kW	Vol. 45, p. 80887 12/8/80	Yes	
QF81-9	Wind	Proposed	4 kW	--	Self-certifying	
QF81-11	Wind	Existing	20 & 30 kW	--	Self-certifying	
QF80-22	Geothermal	Proposed	less than 80 MW	Vol. 45, p. 66855 10/8/80	Application pending	
QF81-7	Geothermal	Proposed	80 MW	Vol. 46, p. 6044 1/21/81	Yes	
QF80-6	Petroleum Coke Feedstock Volatiles 15% natural gas	Proposed	75 MW	Vol. 45, p. 37512 6/3/80	Yes	Bottoming Cycle
QF80-15	Waste Gas	Proposed	175 kW	Vol. 45, p. 56138 8/22/80	Application Pending	

TABLE XIII.4 - Continued

FERC #	Fuel Type	Facility Status	Electrical Generation Capacity	Federal Register Citation	Qualifying Status Granted	Comments
QF80-20	Residual Oil	Proposed	23.3 MW	Vol. 45, p. 61776 9/17/80	Yes	Diesel
QF81-13	Gasified Coal	Proposed	500 MW	Vol. 46, p. 11582 2/9/81	Yes	
QF80-9	Agric. Biomass	Existing	50 MW	Vol. 45, p. 41184 6/18/80	Yes	
QF81-3	Walnut Shells		4.5 MW		Yes	Topping Cycle
QF80-12	Wood Lumber Waste	Proposed	400 MW	Vol. 45, p. 48233	Yes	Topping Cycle
QF80-23	Wood Wastes, natural gas and oil	Existing and Proposed Additions	86 MW	Vol. 45, p. 66858 10/8/80	Yes	Topping Cycle
QF81-4	Wood waste	Proposed	1 MW	Vol. 45, p. 72756 11/3/80	Yes	
QF80-26	Nuclear	Existing	19.5 MW	Vol. 45, p. 73747 11/6/80	Yes	Topping Cycle
QF80-30	--	--	--	--	Application Pending	
QF80-28	--	--	--	--	Application Pending	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80-13
Oahu, Hawaii

Figure XIII.2 Approximate Locations of Existing and Proposed Facilities with Status as Qualifying Cogenerator or Small Power Producer (See Table XIII.4)

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CHAPTER VIV

Electric Region Analyses

SECTION XIV.1

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

(ECAR)

[redacted]

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

The East Central Area Reliability Coordination Agreement (ECAR) was consummated January 14, 1967. This agreement created an organization, the purpose of which is to augment reliability of bulk power supply through coordination of planning and operation of generation and transmission facilities in the East Central area. The ECAR area covers all or portions of nine states: Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

The bulk power membership currently consists of 26 companies (18 systems); 25 are investor-owned and 1 is a cooperative. They are as follows:

Appalachian Power Co. (AEP) 1/
Cincinnati Gas & Electric Co.
Cleveland Electric Illuminating Co.
Columbus and Southern Ohio Electric Co. (AEP)
Consumers Power Co.
Dayton Power and Light Co.
Detroit Edison Co.
Duquesne Light Co.
East Kentucky Power Cooperative
Indiana & Michigan Electric Co. (AEP)
Indiana-Kentucky Electric Corp. 3/
Indianapolis Power & Light Co.
Kentucky Power Co. (AEP)
Kentucky Utilities Co.
Louisville Gas and Electric Co.
Monongahela Power Co. (APS) 2/
Northern Indiana Public Service Co.
Ohio Edison Co.
Ohio Power Co. (AEP)
Ohio Valley Electric Corp.
Pennsylvania Power Co.
Potomac Edison Co. (APS)
Public Service Co. of Indiana
Southern Indiana Gas and Electric Co.
Toledo Edison Co.
West Penn Power Co. (APS)

For purposes of reliability analysis the Staff has subdivided ECAR into 7 Electric Regions. In some of these Regions a power pool or holding company is the dominant power supplier. The Electric Regions in ECAR are:

Electric Region	Identification
1	Allegheny Power System (APS)
2	American Electric Power System (AEP)
13	Central Area Power Coordination Group (CAPCO)
14	Cincinnati, Dayton Group (CD)
15	Kentucky Group
16	Indiana Group (includes all Indiana utilities except Indiana & Michigan Electric Co.)
18	Michigan Electric Coordinated Systems (MECS)

The following sections include data and information concerning the power pool members of ECAR, individual utility members and those other electric systems which which are within ECAR boundaries and report data to ECAR.

1/ (AEP) = subsidiary of American Electric Power System
2/ (APS) = subsidiary of Allegheny Power System
3/ Subsidiary of Ohio Valley Electric Corp.

[redacted]

The Ohio Valley Electric Corp. (OVEC) is a consortium of ten electric companies in ECAR, organized to provide electric power to the Department of Energy Uranium Enrichment Plant at Portsmouth, Ohio. OVEC and its subsidiary, Indiana-Kentucky Electric Corp., have two coal-fired steam electric plants to supply the Portsmouth plant. When the capacity of OVEC and its subsidiary is insufficient to supply Portsmouth needs, the consortium members are obligated to supply the deficiency. When the demand of the Portsmouth plant is low, OVEC and its subsidiary may supply capacity to the consortium members. For the purposes of this report, the OVEC load and capacity are assigned to Electric Region 2, and are included in the total ECAR figures.

ECAR has established an office and provides staff in order to afford a central location for the collection and dissemination of operating data to and from Power Control Centers in the region and to perform required studies and investigations of system performance. The operation of the individual systems in ECAR is directed by the control and dispatch centers of each system, not by ECAR.

Prior to each summer and winter peak load period, ECAR prepares an appraisal report of anticipated transmission system performance. Where the appraisal procedure indicates a potential contingency leading to localized problems, the matter is referred to the affected system(s) for further study and development of appropriate operating instructions.

A study of the Emergency Transfer Capabilities (ETC) between ECAR and adjacent regions was conducted recently by the ECAR systems. The ETC values determined from the study are shown below:

Table 1.1
Emergency Transfer Capability
Between ECAR and other Council Areas

Transfer Direction	Non-Simultaneous Emergency Transfer Capability-MW Summer 1980	Non-Simultaneous Emergency Transfer Capability-MW Winter 1980-81
ECAR to MAAC	3150*	3300+
ECAR to NPCC (NYPP)	3000*	3300+
ECAR to MAIN	2900	4550
ECAR to SERC (TVA)	2900	1900
ECAR to SERC (VACAR)	2250*	1150
ECAR from MAAC	3050	3300+
ECAR from NPCC (NYPP)	2900	3300+
ECAR from MAIN	4000+	3350
ECAR from SERC (TVA)	2000	3100
ECAR from SERC (VACAR)	3300+*	3300+*

+ indicates capability exceeds tabulated amount.
* ETC Values determined with established operating procedures in effect.

In the April 1, 1981 ERA-411 report, ECAR expressed concern that area reliability and reserve margins could be adversely affected by the slippage of in-service dates of new generating units. These slippages could result from environmental constraints, environmental regulations which are not cost effective, diminished financial viability, or construction-related causes. Because of the potential for higher levels of demands than projected, slippage of units could lead to inability to meet load requirements. The following was reported by ECAR in response to ERA-411, Item 3B, Assessment of Adequacy of Margin for the Initial Five Years Reporting Period:

[redacted]

(Quoted from the ECAR ERA-411 Reported dated April 1, 1981)

"An assessment of the load and capacity conditions reported in the 1980 ECAR Response to DOE/ERA led to the conclusion that the overall reserve situation projected for the ECAR region throughout the 1980-1989 period would be at a level which was less than desired if generating unit unavailability continued at the then current level and the load and capacity conditions reported in that response were to materialize. A preliminary examination of the load and capacity data in this response indicates that an improvement in the expected reliability level for ECAR over that which was determined for the conditions reported in the 1980 response can be anticipated. However, the level in some years will still be less than desired. This preliminary assessment is based on the assumption that generating unit unavailability will continue at the current level. Experience has shown that the calculated reliability level associated with projected generating capacity reserves is more sensitive to capacity unavailability than to any other factor. Efforts to improve availability are continuing, but these may well be negated by the adverse affects of poor quality fuel and environmental restrictions.

"A comparison of the load and capacity conditions reported in this response with those reported last year shows that the magnitude of the capacity reduction is very nearly the same as the magnitude of the load forecast reduction. Thus, some improvement in the reliability level for ECAR is expected since the magnitude of the projected reserves, in MW, is not significantly different from those projected one year ago. The lower load forecast, in part, reflects an expectation that the current lower level of economic growth in some areas coupled with conservation efforts in the ECAR region will continue.

"The capacity commitments during the first five years of the reporting period are expected to be reasonably firm, provided that licensing of the five nuclear generating units 1/ scheduled for service during this period can be accomplished in a timely manner. However, there is uncertainty associated with any construction schedule and one or more of the coal-fired generating unit additions during this period may also be subject to delay because of circumstances such as construction difficulties, licensing problems, or suspension of construction due to inability to finance. Uncertainty in the load forecast, uncertainty about improvement in generation availability, uncertainty about the capability loss (both temporary and permanent) attributable to the installation of environmental control equipment, and the expected adverse impact of that control equipment on the performance of generating units are additional reasons why the continuation of this generation commitment would be prudent so as to preserve the reliability of the region to the extent possible.

"For the later five years of the reporting period the scheduled generating capacity additions include both committed generation and other generation that is projected to be required. Nevertheless, the schedule for this period does indicate a substantial deferment of the generation that was reported last year. Nuclear units which are in various stages of construction comprise approximately 20 percent of the projected generation additions during this five-year period. Other types of generation which are not currently under construction and are therefore subject to licensing and other delay considerations constitute nearly 30 percent. Thus, there is a reasonable doubt as to whether or not up to one-half of the capability scheduled to be added during this period can be completed as projected. If generation unavailability continues at its present rate, all of these generation additions will be needed, even with the

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1/ ECAR here refers to Zimmer 1, Perry 1, Midland 1, Midland 2, Enrico Fermi 2.

much lower load projections, if ECAR is to continue to experience a level of reliability which approaches that anticipated during the first five years of the reporting period."

Staff analysis of power supply and demand in the seven Electric Regions within ECAR follows.

ECAR has reported minor changes in the net of scheduled imports and exports for MECS (Electric Region 18) for summer 1985 and winter 1985-86. These changes were received too late to be incorporated in the tables. They are of minor significance.

A. Allegheny Power System (APS)
Electric Region 1

Historical Perspective

The Allegheny Power System, Inc. (APS) is the parent company of an electric system consisting of the Monongahela Power Company, the Potomac Edison Company, West Penn Power Company, and their subsidiaries. The three operating companies serve over 1 million customers in southwestern and north central Pennsylvania, the northern portion of West Virginia, the western portion of Maryland and a small portion of northwestern Virginia.

The three companies are strongly interconnected through 500 KV, 345 KV and 230 KV transmission lines. There are also interconnections at those voltages with other systems in ECAR, with General Public Utilities, Baltimore Gas & Electric Company, and Potomac Electric Power Company in MAAC, and with Virginia Electric & Power Company in SERC.

APS historically has been a winter peaking region. Table 1A.1 shows the region's actual annual net energy, summer and winter peak demands, and load factors for the period 1977-1980.

TABLE 1A.1

ACTUAL ANNUAL NET ENERGY, PEAK DEMANDS, AND LOAD FACTORS

ALLEGHENY POWER SYSTEM REGION

		NET ENERGY	SUMMER PEAK		WINTER PEAK		
YEAR	G W H	PERCENT CHANGE	M W	PERCENT CHANGE	M W	PERCENT CHANGE	LOAD FACTOR
1977	29,551	-	4,539	-	5,174	-	65
1978	30,166	2.1	4,632	2.0	5,335	3.1	65
1979	31,813	5.5	4,676	0.9	5,272	(1.2)	69
1980	32,588	2.4	4,903	4.9	5,564	5.5	67

BASED ON ECAR ERA-411 REPORTS

The summer peak demands are dependent upon climatic conditions and are sensitive to temperature and humidity. Usually the summer peak will occur in July or August, while the winter peak can occur in any of the winter months.

Annual energy requirements over the 1977/1980 period have grown at a compound rate of 3.3% per year. This is a higher growth rate than was experienced by several other regions in ECAR.

During the period 1977-1980 the percent installed capacity, unavailable for reasons other than scheduled maintenance, averaged 20.7% at the time of the summer peak and 21.9% at the time of the winter peak. Over this period full forced outages averaged 9.5% during the summer and 11.6% during the winter; "other" unavailable capacity averaged 11.2% during the summer and 10.3% during the winter. Scheduled maintenance outages, which are under utility control, averaged 9.5% and 4.5% for summer and winter, respectively, over the 1977-1980 period.

The capacity reserve margins for the 1977-1980 period are shown on Table 1A.7. These values include the effects of scheduled maintenance and forced outages. Other unavailable capacity has been combined with forced outages for the 1977-1979 period. However, it is listed specifically for the 1980-1990 period.

There was a substantial increase in the forced outage rates on the APS system during the 1977-1979 period. This increase in unavailable capacity was the result of persistent and lengthy outages of several large generating units on the APS system. This situation caused actual reserves to be negative for the 1977-1979 period (Table 1A.7). However, APS was able to mitigate the effects of these capacity shortfalls by securing short-term power purchases and emergency transfers from neighboring utilities.

Current Perspective

The peak demand forecast for the summer of 1981 is 4,900 megawatts. This is 3 megawatts less than the actual 1980 summer peak demand and 372 MW less than the 1980-81 winter peak. The summer peak demand has increased on average at 2.5% per year for the last four years in the APS area. Most of this growth occurred between 1979 and 1980 because of the unusually high peak demand during the summer of 1980. This was caused by extremely hot weather.

The 1981-1982 winter peak demand is expected to be 5,540 MW. This would be 0.4% higher than the 1980-1981 peak. The winter peak demand has also increased by an average of 2.5% per year for the last four years.

Planned capability to meet the expected 1981 summer and winter peak demands is projected to be 7,419 megawatts and 7,627 megawatts respectively. No major additions are included in the planned capability for the coming summer season. Pleasants #2, a coal-fired plant, is scheduled to be uprated by 61 MW in July 1981 and has been included as available for the summer 1981 season.

Scheduled contracts for power purchases or sales include a 300 MW sale to Virginia Electric & Power Company (VEPCO) and a non-firm purchase of 153 MW from the Ohio Valley Electric Corporation.

After adjustments for net transactions (purchases and sales), planned reserves, as shown on Table 1A.2, are projected to be 2,519 MW or 51.4% for summer 1981. Actual reserves are projected at 131 MW or 2.7%. Planned reserves for winter 1981-1982 are projected to be 2,087 MW or 37.7%. Actual reserves are projected to be 491 MW or 8.9%.

In the ECAR ERA-411 report for the 1981-1990 period, APS does not project the amount of unavailable capability due to scheduled maintenance, forced outages or other reasons. However, these have been developed by Staff using the four year average for the 1977-1980 period and are shown on Table 1A.2, Lines 9, 13, and 17.

TABLE 1A.2

CURRENT CAPABILITY(MW) AND RESERVES (MW AND PERCENT)

ALLEGHENY POWER SYSTEM REGION

	1981 SUMMER	1981 WINTER
1. PLANNED CAPABILITY (MW)	7419	7627
2. PEAK DEMAND (MW)	4900	5540
3. PLANNED RESERVES (MW)(1-2)	2519	2087
4. PLANNED RESERVES (%) (3/2) X 100	51.4	37.7
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-147	418
6. TOTAL CAPABILITY (MW) (1+5)	7272	8045
7. TOTAL RESERVES (MW) (6-2)	2372	2505
8. TOTAL RESERVES (%) (7/2) X 100	48.4	45.2
9. SCHEDULED MAINTENANCE (MW)	705	343
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	6567	7702
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1667	2162
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	34.0	39.0
13. FULL FORCED OUTAGES (MW)	705	885
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	5862	6817
15. AVAILABLE RESERVES (MW) (14-2)	962	1277
16. AVAILABLE RESERVES (%) (15/2) X 100	19.6	23.1
17. OTHER UNAVAILABLE CAPABILITY (MW)	831	786
18. AVAILABLE CAPABILITY (MW) (14-17)	5031	6031
19. ACTUAL RESERVES (MW) (18-2)	131	491
20. ACTUAL RESERVES (%) (19/2) X 100	2.7	8.9

BASED ON ECAR ERA-411 REPORT DATED APRIL 1, 1981 AND FPC 12E-2 REPORTS

The systems in the APS region are governed by ECAR Document No. 2, Daily Operating Reserve Agreement. This agreement specifies that each system must provide: (1) an amount of spinning reserve within the control area of the system equal to three percent of the maximum 60-minute integrated clock-hour internal load predicted for the day, to provide for load regulation and system frequency regulation; (2) an amount of reserve equal to three percent of the maximum 60-minute integrated clock-hour native load predicted for the day, times the system's allocating constant, to provide protection against unexpected loss of generation. The latter portion of operating reserve must be capable of being synchronized with the system within ten minutes and may be allocated among spinning reserve, non-spinning reserve (interruptible load or quick start capacity), and prescheduled assistance from other systems.

[redacted]

The APS region is heavily dependent upon coal for the generation of electricity. Table 1A.3 shows that approximately 93% of the existing generating capability is fired by coal. Only 6% of the APS generating capacity is oil-fired. There are no nuclear facilities installed in the region and hydroelectric generation is an insignificant portion of the total.

For the 1981 summer season no major transmission lines are scheduled for completion. There are at present no definable delays in critical bulk power transmission facilities planned or under construction and all transmission facilities are expected to be in service when needed.

TABLE 1A.3

PLANNED CAPABILITY BY PRIME MOVER

ALLEGHENY POWER SYSTEM REGION

APS CAPABILITY BY PRIME MOVER AND FUEL TYPE - 1981

CAPACITY TYPE	FUEL TYPE	SUMMER 1981 CAPABILITY	
		MW	%
STEAM	NUCLEAR	0	0
STEAM	COAL	6,908	93.1
STEAM	OIL	452	6.1
STEAM	GAS	0	0
HYDRO	-	59	0.8
PUMP STORAGE	-	0	0
GAS TURBINE & DIESEL	OIL	0	0
GAS TURBINE	GAS	0	0
COMBINE CYCLE	OIL	0	0
COMBINE CYCLE	GAS	0	0
OTHER		0	0
TOTAL		7,419	100.0

BASED ON ECAR ERA-411 REPORT DATED APRIL 1, 1981

Future Perspective

Table 1A.4 shows projected energy requirements and peak demands for the period 1981-1990.

The winter peak demands are projected to increase at an annual compound rate of 4.2% during the 1981-1985 period, 4.0% during 1986-1990 period and at 4.1% during 1981-1990 period. These rates are higher than the winter 1977-1980 annual growth of 2.5%.

[redacted]

No new capacity additions are projected for the 1981-1984 period. Summer capability is expected to increase by 22% in the 1985-90 period and winter capability is expected to increase by 20% during this period.

The energy requirements are projected to increase at an annual compound rate of 4.2% from 1981 to 1985, 3.7% from 1986 to 1990 and 3.9% for the overall period 1981-1990.

TABLE 1A.4

PROJECTED ENERGY AND PEAK DEMAND

ALLEGHENY POWER SYSTEM REGION

YEAR	ENERGY REQUIREMENTS		SUMMER PEAK DEMAND		WINTER PEAK DEMAND		ANNUAL LOAD FACTOR
	GWH	PERCENT GROWTH	MW	PERCENT GROWTH	MW	PERCENT GROWTH	PERCENT
1981	32,800	0.7	4,900	(0.0)	5,540	(0.4)	68
1982	34,400	4.9	5,075	3.6	5,830	5.2	67
1983	35,700	3.8	5,245	3.3	6,050	3.8	67
1984	37,300	4.5	5,450	3.9	6,295	4.0	68
1985	38,700	3.8	5,655	3.8	6,540	3.9	68
GROWTH 81-85		4.2		3.7		4.2	
1986	40,200	3.9	5,855	3.5	6,795	3.9	68
1987	41,600	3.5	6,045	3.2	7,080	4.2	67
1988	43,200	3.8	6,270	3.7	7,355	3.9	67
1989	44,800	3.8	6,495	3.6	7,635	3.8	67
1990	46,400	3.6	6,725	3.5	7,950	4.1	67
GROWTH 86-90		3.7		3.5		4.0	
GROWTH 81-90		3.9		3.6		4.1	

BASED ON ECAR ERA-411 REPORT DATED APRIL 1, 1981

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[redacted]

The summer and winter capability of units installed in the Region for the period 1981-1990 is listed by type of fuel in Tables 1A.6.1 and 1A.6.2. Major generating unit additions during the period are given in Table 1A.5.

TABLE 1A.5

MAJOR FUTURE GENERATING UNIT IN-SERVICE DATES

ALLEGHENY POWER SYSTEM REGION

UTILITY	PLANT NAME	NAME PLATE CAPACITY (MW)	ORIGINAL IN-SERVICE DATE	IN-SERVICE DATE AS OF APRIL 1980	PRESENT IN-SERVICE DATE
		COAL			
APS	L. ARMSTRONG #1	630	MAY 1984	JUN 1986	SEP 1988
APS	L. ARMSTRONG #2	630	MAR 1985	SEP 1987	SEP 1990
		PUMPED STORAGE			
APS	PUMP STORAGE #1	500	-	-	OCT 1985
APS	PUMP STORAGE #2	500	-	-	OCT 1986
APS	DAVIS #1-4	1000	JUN 1987	JUN 1987	CANCELLED

BASED ON ECAR ERA-411 REPORT DATED APRIL 1, 1981

Coal is the primary fuel for about 93% of the existing generating capability of the region. This percentage is expected to decrease to 83% by 1990, due to the proposed installation of a 2000 MW pumped storage plant in Virginia by VEPCO. APS will have a 50% share (1000 MW) of this plant, which is currently scheduled to come on line in 1985 and 1986 in 500 MW increments. In addition to the pumped storage plant, two of the three 630 MW coal-fired units of the Lower Armstrong plant are proposed for installation in 1988 and 1989.

Actual reserves for APS for the period 1982-1990 (Tables 1A.8.1, 1A.8.2 and 1A.8.3) range from a high of 8.9% in the winter of 1981 to a low of -12.2% in the summer of 1985.

Starting in the summer of 1982 actual reserve margins for APS are projected to be negative. Planned reserves are generally greater than 21% throughout the forecast period. However, due to the large amounts of capacity that are forecasted to be unavailable, reserve margin deficits may be as large as 800 MW.

The most recent ECAR appraisal studies of the APS transmission line status for Summer 1980 and Winter 1980-81 indicate that timely completion of the scheduled transmission facility additions would insure that the reliability of the bulk power transmission system within ECAR could be maintained at a high level.

BEST DOCUMENT AVAILABLE

TABLE 1A.6.1

SUMMER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

ALLEGHENY POWER SYSTEM REGION

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL COMBUST. TURBINE	OIL INTERNAL COMBUST.	NATURAL GAS STEAM	NATURAL GAS COMBUST. TURBINE	NATURAL GAS INTERNAL COMBUST.	HYDRO CONVENT.	HYDRO PUMPED STORAGE	TOTAL CAPABILITY
1981	0	6908	452	0	0	0	0	0	59	0	7419
% TOTAL	0.0	93.1	6.1	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1982	0	6908	452	0	0	0	0	0	59	0	7419
% TOTAL	0.0	93.1	6.1	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1983	0	6898	452	0	0	0	0	0	59	0	7409
% TOTAL	0.0	93.1	6.1	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1984	0	6898	452	0	0	0	0	0	59	0	7409
% TOTAL	0.0	93.1	6.1	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1984	0	6898	452	0	0	0	0	0	59	0	7409
% TOTAL	0.0	93.1	6.1	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1986	0	6898	452	0	0	0	0	0	59	500	7909
% TOTAL	0.0	87.2	5.7	0.0	0.0	0.0	0.0	0.0	0.8	6.3	100.0
1987	0	6898	452	0	0	0	0	0	59	1000	8409
% TOTAL	0.0	82.0	5.4	0.0	0.0	0.0	0.0	0.0	0.7	11.9	100.0
1988	0	6898	452	0	0	0	0	0	59	1000	8409
% TOTAL	0.0	82.0	5.4	0.0	0.0	0.0	0.0	0.0	0.7	11.9	100.0
1989	0	7528	452	0	0	0	0	0	59	1000	9039
% TOTAL	0.0	83.3	5.0	0.0	0.0	0.0	0.0	0.0	0.7	11.0	100.0
1990	0	7528	452	0	0	0	0	0	59	1000	9039
% TOTAL	0.0	83.3	5.0	0.0	0.0	0.0	0.0	0.0	0.7	11.0	100.0

Based on ECAR ERA-411 Report dated April 1, 1981

TABLE 1A.6.2

WINTER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

ALLEGHENY POWER SYSTEM REGION

			OIL			NATURAL GAS			HYDRO		
YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	TOTAL CAPABILITY
1981	0	7109	456	0	0	0	0	0	62	0	7627
% TOTAL	0.0	93.2	6.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1982	0	7111	456	0	0	0	0	0	62	0	7619
% TOTAL	0.0	93.3	5.9	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1983	0	7111	456	0	0	0	0	0	62	0	7619
% TOTAL	0.0	93.3	5.9	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1984	0	7111	456	0	0	0	0	0	62	0	7619
% TOTAL	0.0	93.3	5.9	0.0	0.0	0.0	0.0	0.0	0.8	0.0	100.0
1985	0	7111	456	0	0	0	0	0	62	500	8119
% TOTAL	0.0	87.6	5.6	0.0	0.0	0.0	0.0	0.0	0.7	6.1	100.0
1986	0	7111	456	0	0	0	0	0	62	1000	8619
% TOTAL	0.0	82.5	5.2	0.0	0.0	0.0	0.0	0.0	0.7	11.6	100.0
1987	0	7111	456	0	0	0	0	0	62	1000	8619
% TOTAL	0.0	82.5	5.2	0.0	0.0	0.0	0.0	0.0	0.7	11.6	100.0
1988	0	7741	456	0	0	0	0	0	62	1000	9249
% TOTAL	0.0	83.7	4.9	0.0	0.0	0.0	0.0	0.0	0.6	10.8	100.0
1989	0	7741	456	0	0	0	0	0	62	1000	9249
% TOTAL	0.0	83.7	4.9	0.0	0.0	0.0	0.0	0.0	0.6	10.8	100.0
1990	0	8371	312	0	0	0	0	0	62	1000	9745
% TOTAL	0.0	85.9	3.2	0.0	0.0	0.0	0.0	0.0	0.6	10.3	100.0

Based on ECAR ERA-411 Report dated April 1, 1981

TABLE 1A.7

HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

ALLEGHENY POWER SYSTEM REGION

	1977		1978		1979		1980	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	6203	6248	6203	6417	6776	6997	6816	7568
2. PEAK DEMAND (MW)	4539	5174	4632	5335	4676	5272	4903	5564
3. PLANNED RESERVES (MW)(1-2)	1664	1074	1571	1082	2100	1725	1913	2004
4. PLANNED RESERVES (%) (3/2) X 100	36.7	20.8	33.9	20.3	44.9	32.7	39.0	36.0
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-313	-50	-50	-50	-50	250	799	-320
6. TOTAL CAPABILITY (MW) (1+5)	5890	6198	6153	6367	6726	7247	7615	7248
7. TOTAL RESERVES (MW) (6-2)	1351	1024	1521	1032	2050	1975	2712	1684
8. TOTAL RESERVES (%) (7/2) X 100	29.8	19.8	32.8	19.3	43.8	37.5	55.3	30.3
9. SCHEDULED MAINTENANCE (MW)	596	1195	500	0	669	186	1296	309
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	5294	5003	5653	6367	6057	7061	6319	6939
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	755	-171	1021	1032	1381	1789	1416	1375
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	16.6	-3.3	22.0	19.3	29.5	33.9	28.9	24.7
13. FULL FORCED OUTAGES (MW)	947	3359	1685	1308	1834	1987	500	330
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	4347	1644	3968	5059	4223	5074	5819	6609
15. AVAILABLE RESERVES (MW) (14-2)	-192	-3530	-664	-276	-453	-198	916	1045
16. AVAILABLE RESERVES (%) (15/2) X 100	-4.2	-68.2	-14.3	-5.2	-9.7	-3.8	18.7	18.8
17. OTHER UNAVAILABLE CAPABILITY (MW)	0	0	0	0	0	0	695	823
18. AVAILABLE CAPABILITY (MW) (14-17)	4347	1644	3968	5059	4223	5074	5124	5786
19. ACTUAL RESERVES (MW) (18-2)	-192	-3530	-664	-276	-453	-198	221	222
20. ACTUAL RESERVES (%) (19/2) X 100	-4.2	-68.2	-14.3	-5.2	-9.7	-3.8	4.5	4.0

Based on ECAR ERA-411 Report dated April 1, 1981, and FPC 12E-2 Reports for 1977-1980

TABLE 1A.8.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

ALLEGHENY POWER SYSTEM REGION

	1982		1983		1984	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	7419	7619	7409	7619	7409	7619
2. PEAK DEMAND (MW)	5075	5830	5245	6050	5450	6295
3. PLANNED RESERVES (MW)(1-2)	2344	1789	2164	1569	1959	1324
4. PLANNED RESERVES (%) (3/2) X 100	46.2	30.7	41.3	25.9	35.9	21.0
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-186	396	-208	396	-208	396
6. TOTAL CAPABILITY (MW) (1+5)	7233	8015	7201	8015	7201	8015
7. TOTAL RESERVES (MW) (6-2)	2158	2185	1956	1965	1751	1720
8. TOTAL RESERVES (%) (7/2) X 100	42.5	37.5	37.3	32.5	32.1	27.3
9. SCHEDULED MAINTENANCE (MW)	705	343	704	343	704	343
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	6528	7672	6497	7672	6497	7672
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1453	1842	1252	1622	1047	1377
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	28.6	31.6	23.9	26.8	19.2	21.9
13. FULL FORCED OUTAGES (MW)	705	884	704	884	704	884
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	5823	6788	5793	6788	5793	6788
15. AVAILABLE RESERVES (MW) (14-2)	748	958	548	738	343	493
16. AVAILABLE RESERVES (%) (15/2) X 100	14.7	16.4	10.4	12.2	6.3	7.8
17. OTHER UNAVAILABLE CAPABILITY (MW)	831	785	830	785	830	785
18. AVAILABLE CAPABILITY (MW) (14-17)	4992	6003	4963	6003	4963	6003
19. ACTUAL RESERVES (MW) (18-2)	-83	173	-282	-47	-487	-292
20. ACTUAL RESERVES (%) (19/2) X 100	-1.6	3.0	-5.4	-0.8	-8.9	-4.6

Based on ECAR ERA-411 Report dated April 1, 1981, and FPC 12E-2 Reports for 1977-1980

TABLE 1A.8.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

ALLEGHENY POWER SYSTEM REGION

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	7409	8119	7909	8619	8409	8619
2. PEAK DEMAND (MW)	5655	6540	5855	6795	6045	7080
3. PLANNED RESERVES (MW)(1-2)	1754	1579	2054	1824	2364	1539
4. PLANNED RESERVES (%) (3/2) X 100	31.0	24.1	35.1	26.8	39.1	21.7
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-208	396	92	85	83	40
6. TOTAL CAPABILITY (MW) (1+5)	7201	8515	8001	8704	8492	8659
7. TOTAL RESERVES (MW) (6-2)	1546	1975	2146	1909	2447	1579
8. TOTAL RESERVES (%) (7/2) X 100	27.3	30.2	36.7	28.1	40.5	22.3
9. SCHEDULED MAINTENANCE (MW)	704	365	751	388	799	388
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	6497	8150	7250	8316	7693	8271
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	842	1610	1395	1521	1648	1191
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	14.9	24.6	23.8	22.4	27.3	16.8
13. FULL FORCED OUTAGES (MW)	704	942	751	1000	799	1000
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	5793	7208	6499	7316	6894	7271
15. AVAILABLE RESERVES (MW) (14-2)	138	668	644	521	849	191
16. AVAILABLE RESERVES (%) (15/2) X 100	2.4	10.2	11.0	7.7	14.0	2.7
17. OTHER UNAVAILABLE CAPABILITY (MW)	830	836	885	888	942	888
18. AVAILABLE CAPABILITY (MW) (14-17)	4963	6372	5614	6428	5952	6383
19. ACTUAL RESERVES (MW) (18-2)	-692	-168	-241	-367	-93	-697
20. ACTUAL RESERVES (%) (19/2) X 100	-12.2	-2.6	-4.1	-5.4	-1.5	-9.8

Based on ECAR ERA-411 Report dated April 1, 1981, and FPC 12E-2 Reports for 1977-1980

TABLE 1A.8.3

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

ALLEGHENY POWER SYSTEM REGION

	1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	8409	9249	9039	9249	9039	9745
2. PEAK DEMAND (MW)	6270	7355	6495	7635	6725	7950
3. PLANNED RESERVES (MW)(1-2)	2139	1894	2544	1614	2314	1795
4. PLANNED RESERVES (%) (3/2) X 100	34.1	25.8	39.2	21.1	34.4	22.6
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	39	0	0	0	0	0
6. TOTAL CAPABILITY (MW) (1+5)	8448	9249	9039	9249	9039	9745
7. TOTAL RESERVES (MW) (6-2)	2178	1894	2544	1614	2314	1795
8. TOTAL RESERVES (%) (7/2) X 100	34.7	25.8	39.2	21.1	34.4	22.6
9. SCHEDULED MAINTENANCE (MW)	799	416	859	416	859	439
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	7649	8833	8180	8833	8180	9306
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1379	1478	1685	1198	1455	1356
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	22.0	20.1	25.9	15.7	21.6	17.1
13. FULL FORCED OUTAGES (MW)	799	1073	859	1073	859	1130
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	6850	7760	7321	7760	7321	8176
15. AVAILABLE RESERVES (MW) (14-2)	580	405	826	125	596	226
16. AVAILABLE RESERVES (%) (15/2) X 100	9.3	5.5	12.7	1.6	8.9	2.8
17. OTHER UNAVAILABLE CAPABILITY (MW)	942	953	1012	953	1012	1003
18. AVAILABLE CAPABILITY (MW) (14-17)	5908	6807	6309	6807	6309	7173
19. ACTUAL RESERVES (MW) (18-2)	-362	-548	-186	-828	-416	-777
20. ACTUAL RESERVES (%) (19/2) X 100	-5.8	-7.5	-2.9	-10.8	-6.2	-9.8

Based on ECAR ERA-411 Report dated April 1, 1981, and FPC 12E-2 Reports for 1977-1980

[redacted]

B. American Electric Power System (AEP)

Electric Region 2

Historical Perspective

The American Electric Power System Region includes American Electric Power Company, Buckeye Power Inc., Ohio Valley Electric Corporation, and the Richmond Power and Light Municipal System. The American Electric Power Company is an electric utility holding company comprising seven wholly-owned subsidiary companies operating in parts of seven states: Ohio, Indiana, Michigan, West Virginia, Virginia, Kentucky, and Tennessee, and includes the recently acquired properties of Columbus and Southern Ohio Electric Company (C&SOE Co.). This report includes the forecast figures for C&SOE Co. The historical data for Region 2 have been adjusted to include C&SOE Co. for comparison purposes. Buckeye Power Inc. is an association of all the electric cooperatives in the State of Ohio. The Ohio Valley Electric Corporation (OVEC), orginally formed by a consortium of ten electric companies in ECAR, provides electric power to the Department of Energy's Uranium Enrichment Plant in Portsmouth, Ohio. The Richmond, Ohio Municipal System has been included in this report for the first time.

The principal companies comprising the AEP System are: Ohio Power Company, Indiana & Michigan Electric Company, Appalachian Power Company, Wheeling Electric Company, Kingsport Power Company, Michigan Power Company, and Columbus and Southern Ohio Electric Company. The American Electric Power System, comprising seven operating companies, functions as a single, integrated power system. Buckeye Power Co. is included in these operations. The operations of this integrated system are coordinated from a single dispatch center located in Canton, Ohio.

The AEP System, though dispersed over seven states and seven companies, is a highly integrated system with major transmission ties of 765 KV, 500 KV, 345 KV and 138 KV. Many interconnections exist with other ECAR systems and with the neighboring utilities in SERC, MAAC, and MAIN.

Buckeye Power Co. generates electric power for Ohio's Co-op customers. Buckeye generating facilities consist of 2 units (630 MW and 600 MW) at the Cardinal electric generating plant. Also located at this plant is a third unit owned by Ohio Power Company, a subsidiary of American Electric Power Company. The station is managed and operated by Cardinal Operating Company for the individual owners. Through an agreement between Buckeye and AEP, Buckeye is allowed to purchase power from Ohio Power Company in the event that Buckeye's own units are unable to satisfy its requirements. The agreement also provides for Ohio Power to use excess generating capacity from Buckeye's Cardinal units until the Buckeye load requirements grow to meet the plant capability.

The AEP region has historically been a winter peaking region. Table 1B.1, on the next page, shows the region's summer and winter peak demands for the period 1977-1980. Peaks fluctuate from year to year in many regions but have fluctuated additionally in this region because of changing contractual sales by OVEC to intra-regional utilities. The AEP region has historically been a winter peaking region.

In three of the reported years, the summer peak has occurred in three different months. The winter peak usually occurs in January or February. Net energy requirements and peak demands reflect the contractual sales of OVEC. Between 1979 and 1980, OVEC sales dropped over 7,000 GWH.

Over the past four years, 1977-1980, generating capacity unavailable due to scheduled maintenance averaged 8.1% of installed capacity at the time of the summer peak and 7.4% at the time of the winter peak. Full forced outages were 4.7% for summer and 5.7% for winter. Other unavailable capacity averaged 5.7% and 5%, respectively.

In the ECAR ERA-411 report for the 1981-1990 forecast period, the AEP group does not project the amount of unavailable capability for scheduled maintenance, forced outages or other reasons. These values however, have been developed by the Staff, using a 4-year average based on historical 1977-1980 data reported in FPC Form 12E-2, and are presented in Table 1B.2 on lines 9, 13, and 17.

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TABLE 1B.1

ACTUAL ANNUAL NET ENERGY, PEAK DEMANDS, AND LOAD FACTORS

AMERICAN ELECTRIC POWER SYSTEM REGION

		NET ENERGY	SUMMER PEAK		WINTER PEAK		
YEAR	G W H	PERCENT CHANGE	M W	PERCENT CHANGE	M W	PERCENT CHANGE	LOAD FACTOR
1977	101,649	-	15,618	-	17,178	-	68
1978	101,056	(0.6)	15,405	(1.4)	17,760	3.4	65
1979	103,605	2.5	14,668	(4.8)	18,766	5.7	63
1980	97,268	(6.1)	14,946	1.9	16,809	(10.4)	66

BASED ON ECAR ERA-411 REPORTS FOR 1978, 1979, 1980, 1981

The historical reserve margins for the 1977-1980 period are shown on Table 1B.2. These values include the effects of scheduled maintenance and forced outages on the reserve margins. Other unavailable capacity is shown as zero for the period 1977-1979 as it has been combined with forced outages. However, it is specifically listed for 1980 and for future projections.

Current Perspectives

The peak demand forecast for summer 1981 is 15,196 MW. This is a 1.7% increase over the actual peak of the previous summer, but a decrease of 2.8% from the 1977 summer peak of 15,618 MW. The winter peak as shown in Table 1B.3 is expected to be 17,772 MW, or a 5.7% increase over the previous winter, but a decrease of 5.3% from the winter of 1979. (See Appendix C for details of the summer 1981 forecast.)

Planned capability to meet the summer and winter peak demands are 24,733 MW and 25,273 MW, respectively. No major additions are included in the planned capability for summer 1981. Four internal combustion engines and three combustion turbines, totaling 126 MW, have been placed on inactive status. Mitchell #1 will be uprated in October 1981 by 140 MW to its full 800 MW capability and will be available for the 1981/1982 winter season. Planned reserves for the 1981/1982 winter season are projected at 7,501 MW or 42.2%. Actual reserves are projected to be adequate at 2,060 MW or 11.6%.

The AEP group has no firm contracts for power transfers with systems in Reliability Councils adjoining ECAR. However, there are many firm and nonfirm contracts with other companies within ECAR.

TABLE 1B.3

CURRENT CAPABILITY(MW) AND RESERVES (MW AND PERCENT)

AMERICAN ELECTRIC POWER SYSTEM REGION

		1981 SUMMER	1981 WINTER
1.	PLANNED CAPABILITY (MW)	24733	25273
2.	PEAK DEMAND (MW)	15196	17772
3.	PLANNED RESERVES (MW)(1-2)	9537	7501
4.	PLANNED RESERVES (%) (3/2) X 100	62.8	42.2
5.	NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-1474	-866
6.	TOTAL CAPABILITY (MW) (1+5)	23259	24407
7.	TOTAL RESERVES (MW) (6-2)	8063	6635
8.	TOTAL RESERVES (%) (7/2) X 100	53.1	37.3
9.	SCHEDULED MAINTENANCE (MW)	1996	1870
10.	CAPABILITY AFTER MAINTENANCE (MW) (6-9)	21263	22537
11.	RESERVES AFTER MAINTENANCE (MW) (10-2)	6067	4765
12.	RESERVES AFTER MAINTENANCE (%) (11/2) X 100	39.9	26.8
13.	FULL FORCED OUTAGES (MW)	1158	1441
14.	AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	20105	21096
15.	AVAILABLE RESERVES (MW) (14-2)	4909	3324
16.	AVAILABLE RESERVES (%) (15/2) X 100	32.3	18.7
17.	OTHER UNAVAILABLE CAPABILITY (MW)	1405	1264
18.	AVAILABLE CAPABILITY (MW) (14-17)	18700	19832
19.	ACTUAL RESERVES (MW) (18-2)	3504	2060
20.	ACTUAL RESERVES (%) (19/2) X 100	23.1	11.6

BASED ON FPC 12E-2 REPORTS FOR 1977-1980 AND
ECAR ERA-411 REPORT DATED APRIL 1, 1981

Future Perspective

Table 1B.4 presents projected energy and peak demands for the period 1981-1985 and 1986-1990.

The summer peak demands are projected to increase at a compound rate of growth of 4.1% during the 1981-1990 period. These rates reflect the leveling of the OVEC contractual fluctations and the bright economic forecast in the area.

Winter peak demands are projected to increase at a compound rate of growth of 3.8% between the 1981-1985 period and 4.1% during the 1986-1990 period and at 3.9% during the overall forecast period.

Energy requirements are projected to grow 4.3% between 1981-1985, 4.4% between 1986-1990, and 4.4% for the overall period.

One critical transmission line, the 765 KV Gavin-Culloden line, which is needed to carry the output of the Gavin-Mountaineer Generating Complex (3900 MW) to various load centers on the AEP system was scheduled for service in May 1980. The project has been delayed as a result of litigation. It now is expected to become operational in December 1982.

TABLE 1B.4

PROJECTED ENERGY AND PEAK DEMAND

AMERICAN ELECTRIC POWER SYSTEM REGION

YEAR	ENERGY REQUIREMENTS		SUMMER PEAK DEMAND		WINTER PEAK DEMAND		ANNUAL LOAD FACTOR
	GWH	PERCENT GROWTH	MW	PERCENT GROWTH	MW	PERCENT GROWTH	PERCENT
1981	101,820	4.7	15,196	1.7	17,772	5.7	65
1982	108,650	6.7	16,075	5.8	18,725	5.2	66
1983	113,390	4.4	16,760	4.3	19,332	3.2	67
1984	116,730	2.9	17,259	3.0	19,931	3.2	67
1985	120,580	3.3	17,812	3.2	20,584	3.3	67
GROWTH 81-85		4.3		4.1		3.8	
1986	124,630	3.4	18,386	3.2	21,373	3.8	67
1987	130,100	4.4	19,062	3.7	22,432	5.0	66
1988	137,060	5.3	20,005	4.9	23,492	4.7	67
1989	143,630	4.8	20,952	4.7	24,287	3.4	68
1990	148,210	3.2	21,618	3.2	25,117	3.4	67
GROWTH 86-90		4.4		4.1		4.1	
GROWTH 81-90		4.3		4.1		3.9	

Based on ECAR ERA-411 Report dated April 1, 1981

The summer and winter capability of units installed in the region for the period 1981-1990 are listed by type of fuel in Table 1B.6.1 and 1B.6.2. Major generating unit additions during the period are given in Table 1B.5.

[redacted]

TABLE 1B.5

MAJOR FUTURE GENERATING UNIT IN-SERVICE DATES

AMERICAN ELECTRIC POWER SYSTEM REGION

UTILITY	PLANT NAME	NAME PLATE CAPACITY (MW)	ORIGINAL IN-SERVICE DATE	IN-SERVICE DATE AS OF APRIL 1980	PRESENT IN-SERVICE DATE
		NUCLEAR			
AEP *	ZIMMER	230	JAN 1980	JAN 1981	JUN 1982
		COAL			
AEP	ROCKPORT #1	1300	JUN 1983	JUN 1983	DEC 1984
AEP	ROCKPORT #2	1300	DEC 1984	DEC 1984	JUN 1986
AEP	LEWIS CO. #1	1300	DEC 1986	DEC 1986	DEC 1988
AEP/COSO	POSTON #5	375	JAN 1987	JAN 1987	CANCELLED
AEP/COSO	POSTON #6	375	JAN 1990	JAN 1990	CANCELLED
		HYDRO			
AEP	GALLIPOLIS	40	JUL 1985	JUL 1985	JUL 1985
AEP	RACINE	40	DEC 1981	DEC 1981	MAR 1983

* AEP'S 28.5% SHARE OF 807 MW UNIT, JOINTLY OWNED WITH CIGE AND DAPL.

Based on ECAR's ERA-411 Report dated April 1, 1981

Currently coal is the primary fuel for about 88% of the planned capability of the region. This percentage will remain about the same for the forecast period, as will the other fuel types. Three major coal-fired units are scheduled in the forecast period, as shown on Table 1B.5, for 1984, 1986, and 1988.

Peak demand, capability, and reserves for the period 1982 through 1990 are shown in Tables 1B.7.1, 1B.7.2, and 1B.7.3. The AEP group does not project the amount of unavailable capability for scheduled maintenance, forced outages or other reasons. These values, however, have been developed by the Staff, using a 4-year average based on historical 1977-1980 data and are presented in Table 1B.2 on lines 9, 13, and 17. Based on the current demand forecast AEP will experience a small capacity deficit of 84 MW in 1989, expanding to 1000 MW in 1990. Furthermore, if the Lewis County 1300 MW unit is not available for service in the winter of 1986 as planned, a 400 MW deficit will occur and deficits will continue for each successive winter until it is available.

TABLE 1B.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

AMERICAN ELECTRIC POWER SYSTEM REGION

	1977		1978		1979		1980	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	22380	23418	24504	24530	23750	24183	23839	25580
2. PEAK DEMAND (MW)	15618	17178	15405	17760	14668	18766	14946	16809
3. PLANNED RESERVES (MW)(1-2)	6762	6240	9099	6770	9082	5417	8893	8771
4. PLANNED RESERVES (%) (3/2) X 100	43.3	36.3	59.1	38.1	61.9	28.9	59.5	52.2
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-2207	168	-1250	-571	-889	-811	-2603	-4953
6. TOTAL CAPABILITY (MW) (1+5)	20173	23586	23254	23959	22861	23372	21236	20627
7. TOTAL RESERVES (MW) (6-2)	4555	6408	7849	6199	8193	4606	6290	3818
8. TOTAL RESERVES (%) (7/2) X 100	29.2	37.3	51.0	34.9	55.9	24.5	42.1	22.7
9. SCHEDULED MAINTENANCE (MW)	745	1169	1541	1166	2307	2079	2632	448
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	19428	22417	21713	22793	20554	21293	18604	20179
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	3810	5239	6308	5033	5886	2527	3658	3370
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	24.4	30.5	40.9	28.3	40.1	13.5	24.5	20.0
13. FULL FORCED OUTAGES (MW)	2112	4770	2969	3206	2028	2884	850	1168
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	17316	17647	18744	19587	18526	18409	17754	19011
15. AVAILABLE RESERVES (MW) (14-2)	1698	469	3339	1827	3858	-357	2808	2202
16. AVAILABLE RESERVES (%) (15/2) X 100	10.9	2.7	21.7	10.3	26.3	-1.9	18.8	13.1
17. OTHER UNAVAILABLE CAPABILITY (MW)	0	0	0	0	0	0	1368	784
18. AVAILABLE CAPABILITY (MW) (14-17)	17316	17647	18744	19587	18526	18409	16386	18227
19. ACTUAL RESERVES (MW) (18-2)	1698	469	3339	1827	3858	-357	1440	1418
20. ACTUAL RESERVES (%) (19/2) X 100	10.9	2.7	21.7	10.3	26.3	-1.9	9.6	8.4

BASED ON ECAR ERA-411 REPORT DATED APRIL 1, 1981 AND FPC 12E-2 REPORTS

TABLE 1B.6.1

SUMMER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

AMERICAN ELECTRIC POWER SYSTEM REGION

			OIL			NATURAL GAS			HYDRO		
YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	TOTAL CAPABILITY
1981	2150	21656	0	173	3	0	0	0	186	565	24733
% TOTAL	8.7	87.6	0.0	0.7	0.0	0.0	0.0	0.0	0.7	2.3	100.0
1982	2376	21796	0	173	3	0	0	0	186	565	25099
% TOTAL	9.5	86.8	0.0	0.7	0.0	0.0	0.0	0.0	0.7	2.3	100.0
1983	2376	21796	0	173	3	0	0	0	226	565	25139
% TOTAL	9.5	86.7	0.0	0.7	0.0	0.0	0.0	0.0	0.8	2.3	100.0
1984	2376	21796	0	203	3	0	0	0	226	565	25169
% TOTAL	9.4	86.6	0.0	0.8	0.0	0.0	0.0	0.0	0.8	2.2	100.0
1985	2376	21796	0	203	3	0	0	0	226	565	25169
% TOTAL	9.4	86.6	0.0	0.8	0.0	0.0	0.0	0.0	0.8	2.2	100.0
1986	2376	23096	0	203	3	0	0	0	266	565	26509
% TOTAL	9.0	87.1	0.0	0.8	0.0	0.0	0.0	0.0	1.0	2.1	100.0
1987	2376	24396	0	203	3	0	0	0	266	565	27809
% TOTAL	8.6	87.7	0.0	0.7	0.0	0.0	0.0	0.0	1.0	2.0	100.0
1988	2376	24396	0	203	3	0	0	0	266	565	27809
% TOTAL	8.6	87.7	0.0	0.7	0.0	0.0	0.0	0.0	1.0	2.0	100.0
1989	2376	25696	0	203	3	0	0	0	266	565	29109
% TOTAL	8.2	88.2	0.0	0.7	0.0	0.0	0.0	0.0	0.9	2.0	100.0
1990	2376	25696	0	203	3	0	0	0	266	565	29109
% TOTAL	8.2	88.2	0.0	0.7	0.0	0.0	0.0	0.0	0.9	2.0	100.0

BASED ON ECAR ERA-411 REPORT DATED APRIL 1, 1981

TABLE 1B.6.2

WINTER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

AMERICAN ELECTRIC POWER SYSTEM REGION

YEAR	NUCLEAR STEAM	COAL STEAM	OIL			NATURAL GAS			HYDRO		TOTAL CAPABILITY
			STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	
1981	2150	22144	0	188	3	0	0	0	223	565	25273
% TOTAL	8.5	87.6	0.0	0.8	0.0	0.0	0.0	0.0	0.9	2.2	100.0
1982	2380	22144	0	188	3	0	0	0	223	565	25503
% TOTAL	9.4	86.7	0.0	0.8	0.0	0.0	0.0	0.0	0.9	2.2	100.0
1983	2380	22144	0	188	3	0	0	0	263	565	25543
% TOTAL	9.3	86.7	0.0	0.8	0.0	0.0	0.0	0.0	1.0	2.2	100.0
1984	2380	23444	0	218	3	0	0	0	263	565	26873
% TOTAL	8.9	87.2	0.0	0.8	0.0	0.0	0.0	0.0	1.0	2.1	100.0
1985	2380	23444	0	218	3	0	0	0	303	565	26913
% TOTAL	8.9	87.1	0.0	0.8	0.0	0.0	0.0	0.0	1.1	2.1	100.0
1986	2380	24744	0	218	3	0	0	0	303	565	28213
% TOTAL	8.4	87.7	0.0	0.8	0.0	0.0	0.0	0.0	1.1	2.0	100.0
1987	2380	24744	0	218	3	0	0	0	303	565	28213
% TOTAL	8.4	87.7	0.0	0.8	0.0	0.0	0.0	0.0	1.1	2.0	100.0
1988	2380	26044	0	218	3	0	0	0	303	565	29513
% TOTAL	8.1	88.3	0.0	0.7	0.0	0.0	0.0	0.0	1.0	1.9	100.0
1989	2380	26044	0	218	3	0	0	0	303	565	29513
% TOTAL	8.1	88.3	0.0	0.7	0.0	0.0	0.0	0.0	1.0	1.9	100.0
1990	2380	26048	0	218	3	0	0	0	303	565	29517
% TOTAL	8.1	88.3	0.0	0.7	0.0	0.0	0.0	0.0	1.0	1.9	100.0

BASED ON ECAR ERA-411 REPORT DATED APRIL 1, 1981

BEST DOCUMENT AVAILABLE

TABLE 13.7.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

AMERICAN ELECTRIC POWER SYSTEM REGION

	1982		1983		1984	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	25099	25503	25139	25543	25169	26873
2. PEAK DEMAND (MW)	16075	18725	16760	19332	17259	19931
3. PLANNED RESERVES (MW)(1-2)	9024	6778	8379	6211	7910	6942
4. PLANNED RESERVES (%) (3/2) X 100	56.1	36.2	50.0	32.1	45.8	34.8
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-850	-775	-759	-802	-786	-798
6. TOTAL CAPABILITY (MW) (1+5)	24249	24728	24380	24741	24383	26075
7. TOTAL RESERVES (MW) (6-2)	8174	6003	7620	5409	7124	6144
8. TOTAL RESERVES (%) (7/2) X 100	50.8	32.1	45.5	28.0	41.3	30.8
9. SCHEDULED MAINTENANCE (MW)	2033	1887	2036	1890	2039	1989
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	22216	22841	22344	22851	22344	24086
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	6141	4116	5584	3519	5085	4155
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	38.2	22.0	33.3	18.2	29.5	20.8
13. FULL FORCED OUTAGES (MW)	1180	1454	1182	1456	1183	1532
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	21036	21387	21162	21395	21161	22554
15. AVAILABLE RESERVES (MW) (14-2)	4961	2662	4402	2063	3902	2623
16. AVAILABLE RESERVES (%) (15/2) X 100	30.9	14.2	26.3	10.7	22.6	13.2
17. OTHER UNAVAILABLE CAPABILITY (MW)	1431	1275	1433	1277	1435	1344
18. AVAILABLE CAPABILITY (MW) (14-17)	19605	20112	19729	20118	19726	21210
19. ACTUAL RESERVES (MW) (18-2)	3530	1387	2969	786	2467	1279
20. ACTUAL RESERVES (%) (19/2) X 100	22.0	7.4	17.7	4.1	14.3	6.4

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	226	0	0	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	19379	20112	19729	20118	19726	21210
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	3304	1387	2969	786	2467	1279
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	20.6	7.4	17.7	4.1	14.3	6.4

BASED ON FPC 12E-2 REPORTS AND ECAR ERA-411 REPORT DATED APRIL 1, 1981

TABLE 1B.7.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

AMERICAN ELECTRIC POWER SYSTEM REGION

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	25169	26913	26509	28213	27809	28213
2. PEAK DEMAND (MW)	17812	20584	18386	21373	19062	22432
3. PLANNED RESERVES (MW)(1-2)	7357	6329	8123	6840	8747	5781
4. PLANNED RESERVES (%) (3/2) X 100	41.3	30.7	44.2	32.0	45.9	25.8
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-782	-794	-778	-741	-731	-147
6. TOTAL CAPABILITY (MW) (1+5)	24387	26119	25731	27472	27078	28066
7. TOTAL RESERVES (MW) (6-2)	6575	5535	7345	6099	8016	5634
8. TOTAL RESERVES (%) (7/2) X 100	36.9	26.9	39.9	28.5	42.1	25.1
9. SCHEDULED MAINTENANCE (MW)	2039	1992	2147	2088	2253	2088
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	22348	24127	23584	25384	24825	25978
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	4536	3543	5198	4011	5763	3546
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	25.5	17.2	28.3	18.8	30.2	15.8
13. FULL FORCED OUTAGES (MW)	1183	1534	1246	1608	1307	1608
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	21165	22593	22338	23776	23518	24370
15. AVAILABLE RESERVES (MW) (14-2)	3353	2009	3952	2403	4456	1938
16. AVAILABLE RESERVES (%) (15/2) X 100	18.8	9.8	21.5	11.2	23.4	8.6
17. OTHER UNAVAILABLE CAPABILITY (MW)	1435	1346	1511	1411	1585	1410
18. AVAILABLE CAPABILITY (MW) (14-17)	19730	21247	20827	22365	21933	22960
19. ACTUAL RESERVES (MW) (18-2)	1918	663	2441	992	2871	528
20. ACTUAL RESERVES (%) (19/2) X 100	10.8	3.2	13.3	4.6	15.1	2.4

BASED ON FPC 12E-2 REPORTS AND ECAR ERA-411 REPORT DATED APRIL 1, 1981

TABLE 1B.7.3

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

AMERICAN ELECTRIC POWER SYSTEM REGION

	1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	27809	29513	29109	29513	29109	29517
2. PEAK DEMAND (MW)	20005	23492	20952	24287	21618	25117
3. PLANNED RESERVES (MW)(1-2)	7804	6021	8157	5226	7491	4400
4. PLANNED RESERVES (%) (3/2) X 100	39.0	25.6	38.9	21.5	34.7	17.5
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-142	27	27	32	32	37
6. TOTAL CAPABILITY (MW) (1+5)	27667	29540	29136	29545	29141	29554
7. TOTAL RESERVES (MW) (6-2)	7662	6048	8184	5258	7523	4437
8. TOTAL RESERVES (%) (7/2) X 100	38.3	25.7	39.1	21.6	34.8	17.7
9. SCHEDULED MAINTENANCE (MW)	2253	2184	2358	2184	2358	2184
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	25414	27356	26778	27361	26783	27370
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	5409	3864	5826	3074	5165	2253
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	27.0	16.4	27.8	12.7	23.9	9.0
13. FULL FORCED OUTAGES (MW)	1307	1682	1368	1682	1368	1682
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	24107	25674	25410	25679	25415	25688
15. AVAILABLE RESERVES (MW) (14-2)	4102	2182	4458	1392	3797	571
16. AVAILABLE RESERVES (%) (15/2) X 100	20.5	9.3	21.3	5.7	17.6	2.3
17. OTHER UNAVAILABLE CAPABILITY (MW)	1585	1476	1659	1476	1659	1476
18. AVAILABLE CAPABILITY (MW) (14-17)	22522	24198	23751	24203	23756	24212
19. ACTUAL RESERVES (MW) (18-2)	2517	706	2799	-84	2138	-905
20. ACTUAL RESERVES (%) (19/2) X 100	12.6	3.0	13.4	-0.3	9.9	-3.6

BASED ON FPC 12E-2 REPORTS AND ECAR ERA-411 REPORT DATED APRIL 1, 1981

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Central Area Power Coordination Group (CAPCO)

Electric Region 13

Historical Perspective

Region 13 includes the Central Area Power Coordination Group (CAPCO) and the municipal systems of Bryan and Cleveland.

CAPCO is a coordinating group with activities in two principal areas: planning and operation. It was originally formed in 1964, and now consists of five major investor-owned electric utilities providing service in northern Ohio and western Pennsylvania. The five member systems are: The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, and the Toledo Edison Company. Each of the five CAPCO companies has its own system dispatch center. Under the terms of the CAPCO Basic Operating Agreement, the members of CAPCO can interchange power and energy on an economy basis with the other members of the pool. The sales or exchanges are subject to the mutual consent of the buyer and seller, but if a transaction is made, it must be in accordance with the schedules set forth in the Basic Operating Agreement. The members of CAPCO are also free to buy, sell, or exchange power and energy with utilities outside of CAPCO.

In 1981, the utilities in the CAPCO region served almost 2.5 million customers. The CAPCO companies, although widely dispersed, are highly interconnected internally and with other ECAR systems via 345 KV and 138 KV transmission lines. CAPCO is in the extreme northeast corner of ECAR; its only direct interconnections are to the east, that is, with utilities in MAAC.

The CAPCO region has historically been a summer peaking area. Table 1C.1 shows the region's summer and winter peaks for the period 1977-1980.

TABLE 1C.1

ACTUAL ANNUAL NET ENERGY, PEAK DEMANDS, AND LOAD FACTORS

CAPCO REGION

	NET ENERGY		SUMMER PEAK		WINTER PEAK		
YEAR	G W H	PERCENT CHANGE	M W	PERCENT CHANGE	M W	PERCENT CHANGE	LOAD FACTOR
1977	64,570	-	11,279	-	10,252	-	65
1978	64,777	0.3	11,087	(1.7)	10,750	4.9	66
1979	65,900	1.7	10,715	(3.4)	10,351	(3.7)	70
1980	64,447	(2.3)	11,291	5.4	10,641	2.8	65

BASED ON FORM ERA-411

[redacted]

There has been 0.1% growth in the overall summer peak during the period 1977-1980. The summer peak demands are usually dependent on climatic conditions and are temperature/humidity sensitive. However, in the reported years, the peak demand has always occurred in the month of July.

The winter peak demand has shown a 3.8% increase over the historical period and has occurred in January or February. These peaks averaged about 6% lower than the corresponding summer peaks.

Net energy requirements showed no growth during 1977-1980 and, in fact, declined slightly.

Over the past four years, 1977-1980, scheduled maintenance on generating equipment averaged 6.8% of installed capacity during the summer peak and 10.0% during the winter peak. Full forced outages were 8.7% during the summer and 13.4% during the winter. Other unavailable capacity averaged 11.9% and 13.8% during the summer and winter peak periods, respectively.

This region has a lot of older capacity on line which is subject to persistent outages. Maintenance must be performed periodically to keep these units operating efficiently.

The historical reserve margins for the 1977-1980 period are shown on Table 1C.2. These values include the effects of scheduled maintenance and forced outages on the reserve margins. Unavailable capacity is shown as zero for the period 1977-1979 because it has been combined with full forced outages. However, it is listed independently for 1980.

During the peak periods, large amounts of forced and other outages - especially in 1977 and 1978 - caused actual reserves to fall well below desirable levels. The situation in 1979 improved significantly and actual reserves were 2% in the summer and rose to 4.9% in the winter. By 1980, these figures were 5.7% and 17.5%, respectively.

Current Perspective

The peak demand forecast for the summer 1981 is 11,620 MW. This is a 2.9% increase over the actual peak of the previous summer, but only 3.0% over the summer peak of 1977. See Appendix C for details regarding summer 1981.

The winter 1981 peak demand forecast is 11,204 MW, or 5.3% over the previous winter. Winter peaks have been growing at a slightly faster rate than the summer peaks.

Planned capability to meet the summer and winter peak demand is 15,089 MW and 15,437 MW, respectively. There are no major capacity additions planned for either the summer or winter seasons during 1981.

The CAPCO area has a firm contract to deliver 300 MW of firm power to the General Public Utilities (MAAC) in the summer of 1981. A receipt of 16 MW for certain Ohio municipals from the Power Authority of the State of New York is scheduled during the same period.

After adjustments for net transactions, total reserves for the 1981 summer season are 3,870 MW or 33.3%. Actual reserves are -259 MW or -2.2%.

For the 1981-1982 winter season total reserves are 4,443 MW or 39.7% and actual reserves are -1,300 MW or -11.6%. Both summer and winter actual reserves could be considered inadequate from a reliability standpoint.

[redacted]

In the ECAR ERA-411 report for the 1981-1990 forecast period, the CAPCO group does not indicate inoperable capability for either scheduled maintenance or possible forced outages. These, however, have been developed by Staff using a four year average based on historical 1977-1980 data. The 1981 capability and reserves are shown in Table 1C.3.

TABLE 1C.3

CURRENT CAPABILITY(MW) AND RESERVES (MW AND PERCENT)

CENTRAL AREA POWER COORDINATION REGION (CAPCO)

	1981 SUMMER	1981 WINTER
1. PLANNED CAPABILITY (MW)	15089	15437
2. PEAK DEMAND (MW)	11620	11204
3. PLANNED RESERVES (MW)(1-2)	3469	4233
4. PLANNED RESERVES (%) (3/2) X 100	29.9	37.8
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	401	210
6. TOTAL CAPABILITY (MW) (1+5)	15490	15647
7. TOTAL RESERVES (MW) (6-2)	3870	4443
8. TOTAL RESERVES (%) (7/2) X 100	33.3	39.7
9. SCHEDULED MAINTENANCE (MW)	1025	1544
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	14465	14103
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	2845	2899
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	24.5	25.9
13. FULL FORCED OUTAGES (MW)	1311	2069
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	13154	12034
15. AVAILABLE RESERVES (MW) (14-2)	1534	830
16. AVAILABLE RESERVES (%) (15/2) X 100	13.2	7.4
17. OTHER UNAVAILABLE CAPABILITY (MW)	1793	2130
18. AVAILABLE CAPABILITY (MW) (14-17)	11361	9904
19. ACTUAL RESERVES (MW) (18-2)	-259	-1300
20. ACTUAL RESERVES (%) (19/2) X 100	-2.2	-11.6

BASED ON FORM ERA-411

Systems in the CAPCO region are covered by ECAR Document No. 2 Daily Operating Reserve Agreement. This agreement is detailed in the section discussing Electric Region 1, APS.

Over 77% of the current generating capacity in the CAPCO region is coal-fired steam, 11% nuclear, 9% oil-fired, 2% pumped storage, and less than 1% is gas-fired.

During the 1981 summer season, two 345 KV transmission lines are scheduled for service - a 16.3 mile interconnection between Ohio Edison Company and Cleveland Electric Illuminating Co. from the Beaver to Avon substations, and a 18.6 mile section from the Cresent to Collier substations of Duquesne Light Company.

Future Perspective

Table 1C.4 shows projected energy and peak demands for the period 1981-1990.

The summer peak demands are projected to increase at a compound rate of growth of 2.9% during the 1981-1985 period, 2.1% during the 1986-1990 period, and 2.4% overall.

Winter peak demands are forecasted to grow at a slightly lower rate, 2.6% between 1981-1985 and 2.0% between 1986-1990, with an overall growth rate of 2.3% through the entire forecast period.

Energy requirements are projected to grow 3.3% between 1981-1985, 2.2% between 1986-1990, and 2.6% for the overall period.

[redacted]

TABLE 1C.4

PROJECTED ENERGY AND PEAK DEMAND

CAPCO REGION

YEAR	ENERGY REQUIREMENTS GWH	ENERGY REQUIREMENTS PERCENT GROWTH	SUMMER PEAK DEMAND MW	SUMMER PEAK DEMAND PERCENT GROWTH	WINTER PEAK DEMAND MW	WINTER PEAK DEMAND PERCENT GROWTH	ANNUAL LOAD FACTOR PERCENT
1981	66,220	2.8	11,620	2.9	11,204	5.3	65
1982	69,230	4.5	12,057	3.8	11,646	3.8	66
1983	71,940	3.9	12,455	3.3	11,941	2.5	66
1984	73,650	2.4	12,776	2.6	12,184	2.0	66
1985	75,270	2.2	13,040	2.1	12,423	2.0	66
GROWTH 81-85		3.3		2.9		2.6	
1986	76,580	1.7	13,253	1.6	12,651	1.8	66
1987	78,290	2.2	13,550	2.2	12,963	2.5	66
1988	80,310	2.6	13,883	2.5	13,233	2.1	66
1989	82,010	2.1	14,136	1.8	13,458	1.7	66
1990	83,430	1.7	14,374	1.7	13,693	1.7	66
GROWTH 86-90		2.2		2.1		2.0	
GROWTH 81-90		2.6		2.4		2.3	

BASED ON FORM ERA-411

Major generating unit additions during the period are given in Table 1C.5. The summer and winter capabilities of units to be available in the region during the period 1981-1990 are listed by type of fuel in Table 1C.6.1 and 1C.6.2.

TABLE 1C.5

MAJOR FUTURE GENERATING UNIT IN-SERVICE DATES

CAPCO REGION

UTILITY	PLANT NAME	NAME PLATE CAPACITY (MW)	ORIGINAL IN-SERVICE DATE	IN-SERVICE DATE AS OF APRIL 1980	PRESENT IN-SERVICE DATE
		NUCLEAR			
CAPCO	PERRY #1	1205	MAY 1983	MAY 1984	MAY 1984
CAPCO	BEAVER VALLEY #2	833	MAY 1984	MAY 1986	MAY 1986
CAPCO	PERRY #2	1205	MAY 1985	MAY 1988	MAY 1988

BASED ON FORM ERA-411

BEST DOCUMENT AVAILABLE/35

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Currently, coal is the primary fuel for about 77% of the region's generating capacity. This percentage will decrease to about 64% as three new nuclear units are put on line. Nuclear capacity is scheduled to increase from 11.5% of the regional total to 26.5% by 1988.

The in-service dates for the three nuclear units that are scheduled during the forecast period are shown on Table 1C.5.

Tables 1C.7.1 to 1C.7.3 show that during the period 1982-1990 the planned reserves range from 21.3% to 41.7%. These are adequate to meet the criteria established by the ECAR agreement. Actual reserves, after considering planned and forced outages, are negative throughout the forecast period and range from -3.2% to -17.5%. The actual reserves are the result of calculations made by DOE based on historical experience. Negative actual reserves are considered to be inadequate from a reliability standpoint. Tables 1C.7.1-1C.7.3 show the effect on actual reserves of a six month delay in nuclear plant completion.

BEST DOCUMENT AVAILABLE

TABLE 1C.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

CENTRAL AREA POWER COORDINATION REGION (CAPCO)

	1977		1978		1979		1980	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	13648	15000	15164	15547	15391	15423	14617	15421
2. PEAK DEMAND (MW)	11279	10252	11087	10750	10715	10351	11291	10641
3. PLANNED RESERVES (MW)(1-2)	2369	4748	4077	4797	4676	5072	3326	4780
4. PLANNED RESERVES (%) (3/2) X 100	21.0	46.3	36.8	44.6	43.6	49.0	29.5	44.9
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	26	-456	-46	68	165	11	2588	-395
6. TOTAL CAPABILITY (MW) (1+5)	13674	14544	15118	15615	15556	15434	17205	15026
7. TOTAL RESERVES (MW) (6-2)	2395	4292	4031	4865	4841	5083	5914	4385
8. TOTAL RESERVES (%) (7/2) X 100	21.2	41.9	36.4	45.3	45.2	49.1	52.4	41.2
9. SCHEDULED MAINTENANCE (MW)	414	656	1005	1075	830	2353	2034	1157
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	13260	13888	14113	14540	14726	13081	15171	13869
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1981	3636	3026	3790	4011	2730	3880	3228
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	17.6	35.5	27.3	35.3	37.4	26.4	34.4	30.3
13. FULL FORCED OUTAGES (MW)	2002	5118	3742	5622	3808	2227	1360	541
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	11258	8770	10371	8918	10918	10854	13811	13328
15. AVAILABLE RESERVES (MW) (14-2)	-21	-1482	-716	-1832	203	503	2520	2687
16. AVAILABLE RESERVES (%) (15/2) X 100	-0.2	-14.5	-6.5	-17.0	1.9	4.9	22.3	25.3
17. OTHER UNAVAILABLE CAPABILITY (MW)	0	0	0	0	0	0	1879	828
18. AVAILABLE CAPABILITY (MW) (14-17)	11258	8770	10371	8918	10918	10854	11932	12500
19. ACTUAL RESERVES (MW) (18-2)	-21	-1482	-716	-1832	203	503	641	1859
20. ACTUAL RESERVES (%) (19/2) X 100	-0.2	-14.5	-6.5	-17.0	1.9	4.9	5.7	17.5

BASED ON FORM ERA-411

TABLE 1C.6.1

SUMMER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

CENTRAL AREA POWER COORDINATION REGION (CAPCO)

			OIL			NATURAL GAS			HYDRO		
YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	TOTAL CAPABILITY
1981	1735	11648	896	427	33	0	20	0	0	330	15089
% TOTAL	11.5	77.2	6.0	2.8	0.2	0.0	0.1	0.0	0.0	2.2	100.0
1982	1693	11683	896	433	33	0	20	0	0	330	15088
% TOTAL	11.2	77.5	5.9	2.9	0.2	0.0	0.1	0.0	0.0	2.2	100.0
1983	1693	11693	896	437	33	0	20	0	0	330	15102
% TOTAL	11.2	77.5	5.9	2.9	0.2	0.0	0.1	0.0	0.0	2.2	100.0
1984	2872	11693	896	441	33	0	20	0	0	330	16285
% TOTAL	17.7	71.8	5.5	2.7	0.2	0.0	0.1	0.0	0.0	2.0	100.0
1985	2872	11768	896	441	33	0	20	0	0	330	16360
% TOTAL	17.6	71.9	5.5	2.7	0.2	0.0	0.1	0.0	0.0	2.0	100.0
1986	3692	11768	896	441	33	0	20	0	0	330	17180
% TOTAL	21.5	68.5	5.2	2.6	0.2	0.0	0.1	0.0	0.0	1.9	100.0
1986	3692	11768	896	441	33	0	20	0	0	330	17180
% TOTAL	21.5	68.5	5.2	2.6	0.2	0.0	0.1	0.0	0.0	1.9	100.0
1988	4871	11778	896	441	33	0	20	0	0	330	18369
% TOTAL	26.5	64.1	4.9	2.4	0.2	0.0	0.1	0.0	0.0	1.8	100.0
1989	4871	11778	896	441	33	0	20	0	0	330	18369
% TOTAL	26.5	64.1	4.9	2.4	0.2	0.0	0.1	0.0	0.0	1.8	100.0
1990	4871	11793	896	441	33	0	20	0	0	330	18384
% TOTAL	26.5	64.1	4.9	2.4	0.2	0.0	0.1	0.0	0.0	1.8	100.0

BASED ON FORM ERA-411

TABLE 1C.6.2

WINTER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

CENTRAL AREA POWER COORDINATION REGION (CAPCO)

			OIL			NATURAL GAS			HYDRO		
YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	TOTAL CAPABILITY
1981	1742	11809	951	513	33	0	24	0	0	365	15437
% TOTAL	11.3	76.5	6.2	3.3	0.2	0.0	0.1	0.0	0.0	2.4	100.0
1982	1700	11819	951	519	33	0	24	0	0	365	15411
% TOTAL	11.0	76.7	6.2	3.4	0.2	0.0	0.1	0.0	0.0	2.4	100.0
1983	1700	11819	951	522	33	0	24	0	0	365	15414
% TOTAL	11.0	76.7	6.2	3.4	0.2	0.0	0.1	0.0	0.0	2.4	100.0
1984	2905	11894	951	525	33	0	24	0	0	365	16697
% TOTAL	17.4	71.3	5.7	3.1	0.2	0.0	0.1	0.0	0.0	2.2	100.0
1985	2905	11894	951	525	33	0	24	0	0	365	16697
% TOTAL	17.4	71.3	5.7	3.1	0.2	0.0	0.1	0.0	0.0	2.2	100.0
1986	3738	11894	951	525	33	0	24	0	0	365	17530
% TOTAL	21.3	67.9	5.4	3.0	0.2	0.0	0.1	0.0	0.0	2.1	100.0
1987	3738	11904	951	525	33	0	24	0	0	365	17540
% TOTAL	21.3	67.9	5.4	3.0	0.2	0.0	0.1	0.0	0.0	2.1	100.0
1988	4943	11904	951	525	33	0	24	0	0	365	18745
% TOTAL	26.4	63.5	5.1	2.8	0.2	0.0	0.1	0.0	0.0	1.9	100.0
1989	4943	11919	951	525	33	0	24	0	0	365	18760
% TOTAL	26.4	63.5	5.1	2.8	0.2	0.0	0.1	0.0	0.0	1.9	100.0
1990	4943	11919	951	525	33	0	24	0	0	365	18760
% TOTAL	26.4	63.5	5.1	2.8	0.2	0.0	0.1	0.0	0.0	1.9	100.0

BASED ON FORM ERA-411

TABLE 10.7.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

CENTRAL AREA POWER COORDINATION REGION (CAPCO)

	1982		1983		1984	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	15088	15411	15102	15414	16285	16697
2. PEAK DEMAND (MW)	12057	11646	12455	11941	12776	12184
3. PLANNED RESERVES (MW)(1-2)	3031	3765	2647	3473	3509	4513
4. PLANNED RESERVES (%) (3/2) X 100	25.1	32.3	21.3	29.1	27.5	37.0
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	237	175	201	173	199	169
6. TOTAL CAPABILITY (MW) (1+5)	15325	15586	15303	15587	16484	16866
7. TOTAL RESERVES (MW) (6-2)	3268	3940	2848	3646	3708	4682
8. TOTAL RESERVES (%) (7/2) X 100	27.1	33.8	22.9	30.5	29.0	38.4
9. SCHEDULED MAINTENANCE (MW)	1025	1541	1027	1541	1107	1670
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	14300	14045	14276	14046	15377	15196
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	2243	2399	1821	2105	2601	3012
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	18.6	20.6	14.6	17.6	20.4	24.7
13. FULL FORCED OUTAGES (MW)	1311	2065	1314	2065	1417	2237
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	12989	11980	12962	11981	13960	12959
15. AVAILABLE RESERVES (MW) (14-2)	932	334	507	40	1184	775
16. AVAILABLE RESERVES (%) (15/2) X 100	7.7	2.9	4.1	0.3	9.3	6.4
17. OTHER UNAVAILABLE CAPABILITY (MW)	1793	2127	1797	2127	1938	2304
18. AVAILABLE CAPABILITY (MW) (14-17)	11196	9853	11165	9854	12022	10655
19. ACTUAL RESERVES (MW) (18-2)	-861	-1793	-1290	-2087	-754	-1529
20. ACTUAL RESERVES (%) (19/2) X 100	-7.1	-15.4	-10.4	-17.5	-5.9	-12.5

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	0	0	0	0	1205	0
22. ACTUAL CAPABILITY (MW) (18-21)	11196	9853	11165	9854	10817	10655
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	-861	-1793	-1290	-2087	-1959	-1529
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2) X 100	-7.1	-15.4	-10.4	-17.5	-15.3	-12.5

BASED ON FORM ERA-411

TABLE 1C.7.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

CENTRAL AREA POWER COORDINATION REGION (CAPCO)

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	16360	16697	17180	17530	17180	17540
2. PEAK DEMAND (MW)	13040	12423	13253	12651	13550	12963
3. PLANNED RESERVES (MW)(1-2)	3320	4274	3927	4879	3630	4577
4. PLANNED RESERVES (%) (3/2) X 100	25.5	34.4	29.6	38.6	26.8	35.3
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	198	168	196	147	179	73
6. TOTAL CAPABILITY (MW) (1+5)	16558	16865	17376	17677	17359	17613
7. TOTAL RESERVES (MW) (6-2)	3518	4442	4123	5026	3809	4650
8. TOTAL RESERVES (%) (7/2) X 100	27.0	35.8	31.1	39.7	28.1	35.9
9. SCHEDULED MAINTENANCE (MW)	1112	1670	1168	1753	1168	1754
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	15446	15195	16208	15924	16191	15859
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	2406	2772	2955	3273	2641	2896
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	18.5	22.3	22.3	25.9	19.5	22.3
13. FULL FORCED OUTAGES (MW)	1423	2237	1495	2349	1495	2350
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	14023	12958	14713	13575	14696	13509
15. AVAILABLE RESERVES (MW) (14-2)	983	535	1460	924	1146	546
16. AVAILABLE RESERVES (%) (15/2) X 100	7.5	4.3	11.0	7.3	8.5	4.2
17. OTHER UNAVAILABLE CAPABILITY (MW)	1947	2304	2044	2419	2044	2420
18. AVAILABLE CAPABILITY (MW) (14-17)	12076	10654	12669	11156	12652	11089
19. ACTUAL RESERVES (MW) (18-2)	-964	-1769	-584	-1495	-898	-1874
20. ACTUAL RESERVES (%) (19/2) X 100	-7.4	-14.2	-4.4	-11.8	-6.6	-14.5

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. NUCLEAR DELAYS (MW)	0	0	833	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	1947	2304	11836	11156	12652	11089
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	-964	-1769	-1417	-1495	-898	-1874
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2) X 100	-7.4	-14.2	-10.7	-11.8	-6.6	-14.5

BASED ON FORM ERA-411

TABLE 10.7.3

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

CENTRAL AREA POWER COORDINATION REGION (CAPCO)

	1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	18369	18745	18369	18760	18384	18760
2. PEAK DEMAND (MW)	13883	13233	14136	13458	14374	13693
3. PLANNED RESERVES (MW)(1-2)	4486	5512	4233	5302	4010	5067
4. PLANNED RESERVES (%) (3/2) X 100	32.3	41.7	29.9	39.4	27.9	37.0
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	108	6	44	5	41	7
6. TOTAL CAPABILITY (MW) (1+5)	18477	18751	18413	18765	18425	18767
7. TOTAL RESERVES (MW) (6-2)	4594	5518	4277	5307	4051	5074
8. TOTAL RESERVES (%) (7/2) X 100	33.1	41.7	30.3	39.4	28.2	37.1
9. SCHEDULED MAINTENANCE (MW)	1249	1875	1249	1876	1250	1876
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	17228	16876	17164	16889	17175	16891
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	3345	3643	3028	3431	2801	3198
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	24.1	27.5	21.4	25.5	19.5	23.4
13. FULL FORCED OUTAGES (MW)	1598	2511	1598	2513	1599	2513
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	15630	14365	15566	14376	15576	14378
15. AVAILABLE RESERVES (MW) (14-2)	1747	1132	1430	918	1202	685
16. AVAILABLE RESERVES (%) (15/2) X 100	12.6	8.6	10.1	6.8	8.4	5.0
17. OTHER UNAVAILABLE CAPABILITY (MW)	2186	2587	2186	2589	2187	2589
18. AVAILABLE CAPABILITY (MW) (14-17)	13444	11778	13380	11787	13389	11789
19. ACTUAL RESERVES (MW) (18-2)	-439	-1455	-756	-1671	-985	-1904
20. ACTUAL RESERVES (%) (19/2) X 100	-3.2	-11.0	-5.3	-12.4	-6.9	-13.9

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	1205	0	0	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	12239	11778	13380	11787	13389	11789
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	-1644	-1455	-756	-1671	-985	-1904
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2) X 100	-11.8	-11.0	-5.3	-12.4	-6.9	-13.9

BASED ON FORM ERA-411

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Cincinnati-Dayton Group (CD)
Electric Region 14

Historical Perspective

The Cincinnati-Dayton Group (CD) includes the Cincinnati Gas and Electric Co., the Dayton Power and Light Company (DAPL) and the municipal system of Hamilton, Ohio. Columbus & Southern Ohio Electric Company, formerly a member of this group and part of the electric region for operating purposes, has been purchased by American Electric Power System and is now included in the AEP area. Historical data used in this report has been adjusted to reflect this change. The municipal system of the city of Hamilton, Ohio, located in this region, is interconnected with Cincinnati Gas and Electric Company. The system has generating capability and purchases energy when required. The Cincinnati and Dayton Companies, located in the central portion of the ECAR Reliability Council, are highly interconnected internally and with neighboring ECAR utilities by 345 KV and 138 KV transmission lines.

The CD region has historically been a summer peaking region. Table 1D.1 shows the region's summer and winter peaks for the period 1977-80.

TABLE 1D.1

ACTUAL ANNUAL NET ENERGY, PEAK DEMANDS, AND LOAD FACTORS

CINCINNATI-DAYTON REGION (CD)

		NET ENERGY	SUMMER PEAK		WINTER PEAK		
YEAR	G W H	PERCENT CHANGE	M W	PERCENT CHANGE	M W	PERCENT CHANGE	LOAD FACTOR
1977	24,715	-	4,848	-	4,741	-	66
1978	25,156	1.8	4,828	(0.5)	4,719	(0.5)	59
1979	25,965	3.2	4,970	2.9	4,432	(6.1)	60
1980	27,074	4.3	5,306	6.8	4,911	10.8	58

BASED ON FORM ERA-411

There has been a compound growth rate of 3.1% in the summer peak during the 1977-1980 period. The summer peak demands are usually dependent on climatic conditions and are temperature/humidity sensitive. In the last four years peaks have occurred in July or August.

The winter peak usually occurs in January or February. Winter peaks have a wide variance. After two years of decline, the peak in 1980 increased by 10.8% over 1979. However, the compound growth rate during the historical period was only 1.2%. Summer-winter diversity has been increasing from 2.2% in 1977 to 8.0% in 1980.

Net energy requirements indicate an increasing rate of growth between 1977 and 1980. The average growth rate during the period was 3.1%. This is considerably higher than other ECAR systems in the Ohio area.

Over the past four years, 1977-1980, scheduled maintenance on generating equipment averaged 8.1% of installed capacity during the summer and winter peak periods. Full forced outages averaged 4.7% and 5.5% of installed capability during the summer and winter peaks, respectively.

The historical reserve margins for the 1977-1980 period are shown on Table 1D.2. These values include the effects of scheduled maintenance, full forced outages and unavailable capacity on the reserve margins.

Current Perspective

The peak forecast for the summer 1981 is 5,352 MW. This is a 46 MW increase (less than 1%) over the previous summer. See Appendix C for details regarding summer 1981.

The peak winter forecast for 1981 is 5,064 MW, or, a 3.1% increase over the winter 1980 peak. Winter peaks have been erratic especially on the Cincinnati system primarily due to weather conditions.

Planned capability to meet the 1981 summer and winter demands is 6,813 MW and 7,027 MW, respectively. East Bend #2, a jointly owned 600 MW coal-fired generating station, went into service in March, 1981 and will be available for the coming summer season. There are no other major capacity additions scheduled to come into service during 1981.

The CD region has no firm power contracts with utilities other than those in the ECAR region.

After adjustments for net transactions total reserves are projected to be 1,627 MW or 30.4% for summer 1981 and actual reserves 176 MW or 3.3% as shown on Table 1D.3.

Total reserves for the 1981/82 winter season are projected to be 2,144 MW or 42.3% and actual reserves 150 MW or 3.0%.

These levels of projected 1981 summer and winter actual reserves could be considered marginal in terms of the provision of reliable service.

In the ECAR ERA-411 report for the 1981-1990 forecast period the CD Group does not indicate inoperable capability for either scheduled maintenance or possible forced outages. These, however, have been developed by Staff, using a four year average based on historical 1977-80 data. These are shown on Table 1D.3.

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TABLE 1D.3

CURRENT CAPABILITY(MW) AND RESERVES (MW AND PERCENT)

CINCINNATI-DAYTON REGION (CD)

	1981 SUMMER	1981 WINTER
1. PLANNED CAPABILITY (MW)	6813	7027
2. PEAK DEMAND (MW)	5352	5064
3. PLANNED RESERVES (MW)(1-2)	1461	1963
4. PLANNED RESERVES (%) (3/2) X 100	27.3	38.8
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	166	181
6. TOTAL CAPABILITY (MW) (1+5)	6979	7208
7. TOTAL RESERVES (MW) (6-2)	1627	2144
8. TOTAL RESERVES (%) (7/2) X 100	30.4	42.3
9. SCHEDULED MAINTENANCE (MW)	552	569
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	6427	6639
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1075	1575
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	20.1	31.1
13. FULL FORCED OUTAGES (MW)	320	386
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	6107	6253
15. AVAILABLE RESERVES (MW) (14-2)	755	1189
16. AVAILABLE RESERVES (%) (15/2) X 100	14.1	23.5
17. OTHER UNAVAILABLE CAPABILITY (MW)	579	1039
18. AVAILABLE CAPABILITY (MW) (14-17)	5528	5214
19. ACTUAL RESERVES (MW) (18-2)	176	150
20. ACTUAL RESERVES (%) (19/2) X 100	3.3	3.0

BASED ON FORM ERA-411

Systems in the CD region are covered by ECAR Document No. 2 Daily Operating Reserve Agreement. This agreement is detailed in the section discussing Electric Region 1, APS.

Almost 86% of the current generating capacity in the CD region is coal-fired steam, 4% oil-fired steam, and 10% gas turbine and internal combustion units fired by oil or gas. There is one MW hydroelectric plant.

During the 1981 summer season only one transmission line is due to be placed in service by DAPL. This 345 KV transmission line will extend 5.5 miles from the Killen station to the Stuart-Marquis substation. It will provide initial station power and deliver the generator output from the proposed Killen station that is due in service in October 1982.

Future Perspective

Table 1D.4 shows projected energy and peak demands for the period 1981-1985 and 1986-1990.

TABLE 1D.4

PROJECTED ENERGY AND PEAK DEMAND

CINNCINATI-DAYTON REGION (CD)

YEAR	ENERGY REQUIREMENTS		SUMMER PEAK DEMAND		WINTER PEAK DEMAND		ANNUAL LOAD FACTOR
	GWH	PERCENT GROWTH	MW	PERCENT GROWTH	MW	PERCENT GROWTH	PERCENT
1981	27,330	0.9	5,352	0.8	5,064	3.1	58
1982	28,540	4.4	5,553	3.8	5,244	3.6	59
1983	29,650	3.9	5,717	3.0	5,405	3.1	59
1984	30,450	2.7	5,873	2.7	5,577	3.2	59
1985	31,470	3.3	6,049	3.0	5,760	3.3	59
GROWTH 81-85		3.6		3.2		3.3	
1986	32,280	2.6	6,206	2.6	5,922	2.8	59
1987	33,390	3.4	6,373	2.7	6,094	2.9	60
1988	34,600	3.6	6,558	2.9	6,272	2.9	60
1989	35,510	2.6	6,710	2.3	6,423	2.4	60
1990	36,320	2.3	6,852	2.1	6,565	2.2	61
GROWTH 86-90		3.0		2.5		2.6	
GROWTH 81-90		3.2		2.8		2.9	

BASED ON FORM ERA-411

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The summer peak demands are projected to increase at a compound rate of growth of 3.2% during the 1981-1985 period, 2.5% during the 1986-1990 period, and 2.8% overall. These rates are consistent with historic growth rates.

Winter peak demands are forecasted to grow at a compound rate of 3.3% between 1981-1985 and 2.6% between 1986-1990, with an overall growth rate of 2.9% through the entire forecast period.

Energy requirements are projected to grow at a compound rate of 3.6% between 1981-1985, 3.0% between 1986-1990 and 3.2% for the overall period. These projected rates are slightly greater than what occurred during the historical period of 1977-1980.

The major generating unit additions during the period are given in Table 1D.5. The summer and winter capabilities of units to be available during the period 1981-1990 are listed by type of fuel in Table 1D.6.1 and 1D.6.2.

TABLE 1D.5

MAJOR FUTURE GENERATING UNIT IN-SERVICE DATES

CINCINNATI-DAYTON REGION (CD)

UTILITY	PLANT NAME	NAME PLATE CAPACITY (MW)	ORIGINAL IN-SERVICE DATE	IN-SERVICE DATE AS OF APRIL 1980	PRESENT IN-SERVICE DATE
		NUCLEAR			
CIGE/DAPL*	ZIMMER #1	577	JAN 1980	JAN 1981	JUN 1982
		COAL			
CIGE/DAPL	EAST BEND #2	600	JAN 1981	JAN 1981	IN-SERVICE
CIGE/DAPL	KILLEN #2	600	NOV 1982	NOV 1982	OCT 1982
CIGE/DAPL	EAST BEND #1	600	NOV 1984	NOV 1985	APR 1988
CIGE/DAPL	KILLEN #1	600	APR 1986	DEC 1985	DEFERRED
CIGE/DAPL	EAST BEND #3	600	APR 1988	NOV 1989	DEFERRED

* UNIT JOINTLY OWNED WITH AEP, TOTAL CAPABILITY OF UNIT IS 800 MW.

BASED ON FORM ERA-411

Currently, coal is the primary fuel for about 86% of the CD region's (summer) capacity. This percentage is expected to decrease very slightly to 85% in 1990, due to the addition of the Zimmer nuclear plant scheduled for 1982 (the first nuclear plant in the region). Nuclear generating capability in 1990 will be about 7% of the regional total.

Two coal-fired generating units, each 600 MW, are scheduled to be installed in the region, one in 1982 and one in 1988. These are shown on Table 1D.5. Two additional 600 MW units have been deferred past the study period.

Planned reserves throughout the forecast period range from 51% in the winter of 1982 to 21.7% in the summer of 1990. These reserve amounts satisfy the ECAR operating agreement. Projected actual reserves range from 9.4% in the winter of 1982 to a low of -6.7% in the winter of 1990. Actual reserves are positive until the winter of 1986 and then generally decrease to a maximum deficit of 44 MW in the winter of 1990. Projected actual reserves during the second half of the decade could be considered inadequate from a reliability standpoint. Reserve margins are shown on Tables 1D.7.1-1D.7.3. The effect on actual reserves of a six month delay in the expected in-service date of the Zimmer nuclear unit is shown on Table 1D.7.1.

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TABLE 1D.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

CINCINNATI-DAYTON REGION (CD)

	1977		1978		1979		1980	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	5805	6024	6300	6481	6266	6430	6217	6426
2. PEAK DEMAND (MW)	4848	4741	4828	4719	4970	4432	5306	4911
3. PLANNED RESERVES (MW)(1-2)	957	1283	1472	1762	1296	1998	911	1515
4. PLANNED RESERVES (%) (3/2) X 100	19.7	27.1	30.5	37.3	26.1	45.1	17.2	30.8
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	157	1259	379	558	1090	412	587	519
6. TOTAL CAPABILITY (MW) (1+5)	5962	7283	6679	7039	7356	6842	6804	6945
7. TOTAL RESERVES (MW) (6-2)	1114	2542	1851	2320	2386	2410	1498	2034
8. TOTAL RESERVES (%) (7/2) X 100	23.0	53.6	[illegible].3	49.2	48.0	54.4	28.2	41.4
9. SCHEDULED MAINTENANCE (MW)	432	1236	962	432	589	717	104	713
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	5530	6047	5717	6607	6767	6125	6700	6232
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	682	1306	889	1888	1797	1693	1394	1321
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	14.1	27.5	18.4	40.0	36.2	38.2	26.3	26.9
13. FULL FORCED OUTAGES (MW)	123	750	124	280	389	223	602	888
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	5407	5297	5593	6327	6378	5902	6098	5344
15. AVAILABLE RESERVES (MW) (14-2)	559	556	765	1608	1408	1470	792	433
16. AVAILABLE RESERVES (%) (15/2) X 100	11.5	11.7	15.8	34.1	28.3	33.2	14.9	8.8
17. OTHER UNAVAILABLE CAPABILITY (MW)	417	931	589	1446	731	485	468	411
18. AVAILABLE CAPABILITY (MW) (14-17)	4990	4366	5004	4681	5647	5417	5530	4933
19. ACTUAL RESERVES (MW) (18-2)	142	-375	176	162	677	985	324	22
20. ACTUAL RESERVES (%) (19/2) X 100	2.9	-7.9	3.6	3.4	13.6	22.2	6.1	0.4

BASED ON FORM ERA-411

TABLE 1D.6.1

SUMMER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

CINCINNATI-DAYTON REGION (CD)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL			NATURAL GAS			HYDRO		TOTAL CAPABILITY
			STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	
1981	0	5848	260	393	42	0	269	0	0	1	6813
% TOTAL	0.0	85.9	3.8	5.8	0.6	0.0	3.9	0.0	0.0	0.0	100.0
1982	566	5709	260	393	42	0	269	0	0	1	7239
% TOTAL	7.8	78.9	3.6	5.4	0.6	0.0	3.7	0.0	0.0	0.0	100.0
1983	566	6309	119	393	42	0	269	0	0	1	7699
% TOTAL	7.4	82.0	1.5	5.1	0.5	0.0	3.5	0.0	0.0	0.0	100.0
1984	566	6448	119	393	42	0	269	0	0	1	7838
% TOTAL	7.2	82.3	1.5	5.0	0.5	0.0	3.4	0.0	0.0	0.0	100.0
1985	566	6448	119	393	42	0	269	0	0	1	7838
% TOTAL	7.2	82.3	1.5	5.0	0.5	0.0	3.4	0.0	0.0	0.0	100.0
1986	566	6448	119	393	42	0	269	0	0	1	7838
% TOTAL	7.2	82.3	1.5	5.0	0.5	0.0	3.4	0.0	0.0	0.0	100.0
1987	566	6448	119	393	42	0	269	0	0	1	7838
% TOTAL	7.2	82.[illegible]	1.5	5.0	0.5	0.0	3.4	0.0	0.0	0.0	100.0
1988	566	70[illegible]	17	393	42	0	269	0	0	1	8336
% TOTAL	6.8	84.6	0.2	4.7	0.5	0.0	3.2	0.0	0.0	0.0	100.0
1989	566	7048	17	393	42	0	269	0	0	1	8336
% TOTAL	6.8	84.6	0.2	4.7	0.5	0.0	3.2	0.0	0.0	0.0	100.0
1990	566	7048	17	393	42	0	269	0	0	1	8336
% TOTAL	6.8	84.6	0.2	4.7	0.5	0.0	3.2	0.0	0.0	0.0	100.0

BASED ON FORM ERA-411

TABLE 1D.6.2

WINTER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

CINCINNATI-DAYTON REGION (CD)

			OIL			NATURAL GAS			HYDRO		
YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE *	TOTAL CAPABILITY
1981	0	5875	264	521	42	0	325	0	0	1	7027
% TOTAL	0.0	83.6	3.8	7.4	0.6	0.0	4.6	0.0	0.0	0.0	100.0
1982	577	6334	121	521	42	0	325	0	0	1	7921
% TOTAL	7.3	80.0	1.5	6.6	0.5	0.0	4.1	0.0	0.0	0.0	100.0
1983	577	6334	121	521	42	0	325	0	0	1	7921
% TOTAL	7.3	80.0	1.5	6.6	0.5	0.0	4.1	0.0	0.0	0.0	100.0
1984	577	6475	121	521	42	0	325	0	0	1	8062
% TOTAL	7.2	80.3	1.5	6.5	0.5	0.0	4.0	0.0	0.0	0.0	100.0
1985	577	6475	121	521	42	0	325	0	0	1	8062
% TOTAL	7.2	80.3	1.5	6.5	0.5	0.0	4.0	0.0	0.0	0.0	100.0
1986	577	6475	121	521	42	0	325	0	0	1	8062
% TOTAL	7.2	80.3	1.5	6.5	0.5	0.0	4.0	0.0	0.0	0.0	100.0
1987	577	6475	121	521	42	0	325	0	0	1	8062
% TOTAL	7.2	80.3	1.5	6.5	0.5	0.0	4.0	0.0	0.0	0.0	100.0
1988	577	7075	19	521	42	0	325	0	0	1	8560
% TOTAL	6.7	82.7	0.2	6.1	0.5	0.0	3.8	0.0	0.0	0.0	100.0
1989	577	7075	19	521	42	0	325	0	0	1	8560
% TOTAL	6.7	82.7	0.2	6.1	0.5	0.0	3.8	0.0	0.0	0.0	100.0
1990	577	7075	19	521	42	0	325	0	0	1	8560
% TOTAL	6.7	82.7	0.2	6.1	0.5	0.0	3.8	0.0	0.0	0.0	100.0

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TABLE 1D.7.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

CINCINNATI-DAYTON REGION (CD)

	1982		1983		1984	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	7239	7921	7699	7921	7838	8062
2. PEAK DEMAND (MW)	5553	5244	5717	5405	5873	5577
3. PLANNED RESERVES (MW)(1-2)	1686	2677	1982	2516	1965	2485
4. PLANNED RESERVES (%) (3/2) X 100	30.4	51.0	34.7	46.5	33.5	44.6
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	78	65	65	65	69	65
6. TOTAL CAPABILITY (MW) (1+5)	7317	7986	7764	7986	7907	8127
7. TOTAL RESERVES (MW) (6-2)	1764	2742	2047	2581	2034	2550
8. TOTAL RESERVES (%) (7/2) X 100	31.8	52.3	35.8	47.8	34.6	45.7
9. SCHEDULED MAINTENANCE (MW)	586	642	624	642	635	653
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	6731	7344	7140	7344	7272	7474
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1178	2100	1423	1939	1399	1897
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	21.2	40.0	24.9	35.9	23.8	34.0
13. FULL FORCED OUTAGES (MW)	340	436	362	436	368	443
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	6391	6908	6778	6908	6904	7031
15. AVAILABLE RESERVES (MW) (14-2)	838	1664	1061	1503	1031	1454
16. AVAILABLE RESERVES (%) (15/2) X 100	15.1	31.7	18.6	27.8	17.6	26.1
17. OTHER UNAVAILABLE CAPABILITY (MW)	615	1172	654	1172	666	1193
18. AVAILABLE CAPABILITY (MW) (14-17)	5776	5736	6124	5736	6238	5838
19. ACTUAL RESERVES (MW) (18-2)	223	492	407	331	365	261
20. ACTUAL RESERVES (%) (19/2) X 100	4.0	9.4	7.1	6.1	6.2	4.7

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	566	0	0	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	5210	5736	6124	5736	6238	5838
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	-343	492	407	331	365	261
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2) X 100	-6.2	9.4	7.1	6.1	6.2	4.7

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TABLE 1D.7.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

CINCINNATI-DAYTON REGION (CD)

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	7838	8062	7838	8062	7838	8062
2. PEAK DEMAND (MW)	6049	5760	6206	5922	6373	6094
3. PLANNED RESERVES (MW)(1-2)	1789	2302	1632	2140	1465	1968
4. PLANNED RESERVES (%) (3/2) X 100	29.6	40.0	26.3	36.1	23.0	32.3
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	73	65	78	57	75	25
6. TOTAL CAPABILITY (MW) (1+5)	7911	8127	7916	8119	7913	8087
7. TOTAL RESERVES (MW) (6-2)	1862	2367	1710	2197	1540	1993
8. TOTAL RESERVES (%) (7/2) X 100	30.8	41.1	27.6	37.1	24.2	32.7
9. SCHEDULED MAINTENANCE (MW)	635	653	635	653	635	653
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	7276	7474	7281	7466	7278	7434
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1227	1714	1075	1544	905	1340
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	20.3	29.8	17.3	26.1	14.2	22.0
13. FULL FORCED OUTAGES (MW)	368	443	368	443	368	443
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	6908	7031	6913	7023	6910	6991
15. AVAILABLE RESERVES (MW) (14-2)	859	1271	707	1101	537	897
16. AVAILABLE RESERVES (%) (15/2) X 100	14.2	22.1	11.4	18.6	8.4	14.7
17. OTHER UNAVAILABLE CAPABILITY (MW)	666	1193	666	1193	666	1193
18. AVAILABLE CAPABILITY (MW) (14-17)	6242	5838	6247	5830	6244	5798
19. ACTUAL RESERVES (MW) (18-2)	193	78	41	-92	-129	-296
20. ACTUAL RESERVES (%) (19/2) X 100	3.2	1.4	0.7	-1.6	-2.0	-4.9

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TABLE 1D.7.3

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

CINCINNATI-DAYTON REGION (CD)

	1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	8336	8560	8336	8560	8336	8560
2. PEAK DEMAND (MW)	6558	6272	6710	6423	6852	6565
3. PLANNED RESERVES (MW)(1-2)	1778	2288	1626	2137	1484	1995
4. PLANNED RESERVES (%) (3/2) X 100	27.1	36.5	24.2	33.3	21.7	30.4
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	50	-4	27	-4	33	-4
6. TOTAL CAPABILITY (MW) (1+5)	8386	8556	8363	8556	8369	8556
7. TOTAL RESERVES (MW) (6-2)	1828	2284	1653	2133	1517	1991
8. TOTAL RESERVES (%) (7/2) X 100	27.9	36.4	24.6	33.2	22.1	30.3
9. SCHEDULED MAINTENANCE (MW)	675	693	675	693	675	693
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	7711	7863	7688	7863	7694	7863
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	1153	1591	978	1440	842	1298
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	17.6	25.4	14.6	22.4	12.3	19.8
13. FULL FORCED OUTAGES (MW)	392	471	392	471	392	471
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	7319	7392	7296	7392	7302	7392
15. AVAILABLE RESERVES (MW) (14-2)	761	1120	586	969	450	827
16. AVAILABLE RESERVES (%) (15/2) X 100	11.6	17.9	8.7	15.1	6.6	12.6
17. OTHER UNAVAILABLE CAPABILITY (MW)	708	1267	708	1267	708	1267
18. AVAILABLE CAPABILITY (MW) (14-17)	6611	6125	6588	6125	6594	6125
19. ACTUAL RESERVES (MW) (18-2)	53	-147	-122	-298	-258	-440
20. ACTUAL RESERVES (%) (19/2) X 100	0.8	-2.3	-1.8	-4.6	-3.8	-6.7

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Kentucky Group
Electric Region 15

Historical Perspective

Electric Region 15 consists of the electric systems in the State of Kentucky (excluding the Kentucky Power Co.) and that portion of the Tennessee Valley Authority located within Kentucky. The major power suppliers in the region are Big Rivers Electric Corp.; Louisville Gas & Electric Co.; East Kentucky Power Cooperative; and Kentucky Utilities Company. Data in this section are also included for the Henderson, Kentucky and Owensboro, Kentucky municipal electric systems, which are within the region.

All of the systems for which data are included are regular or liaison members of the ECAR organization. The two investor-owned utilities and the two municipal systems collectively serve about 489,000 residential customers, 60,000 commercial customers, 82,000 rural customers, and 3,800 industrial customers. The two cooperative systems, Big Rivers and East Kentucky, serve 22 member cooperative systems.

The major transmission voltages in the Kentucky region are 138-kV and 161-kV, although there is one 345-kV interconnection between Louisville Gas & Electric Co., and the Ohio Valley Electric Corporation (OVEC). In addition to OVEC, the systems in Electric Region (ER) 15 have transmission ties with the Ohio Power Co. in ER 2-AEP; with the Central Illinois Public Service Co. and Electric Energy, Inc. in ER 17-ILLMO; with the Public Service Company of Indiana (PSI) and the Southern Indiana Gas & Electric Co. in ER 16-IN; with Cincinnati Gas and Electric Co. in ER 14-CD; and with the Tennessee Valley Authority in ER 11-TVA.

Current Perspective

The 1981 expected summer load and supply situation for Electric Region 15 is reviewed in Appendix C. The 1981-1982 winter situation is discussed below.

The 1981-1982 winter planned capability is estimated to be 7,742 MW, and the peak demand is projected to be 6,012 MW, resulting in planned reserves of 1,730 MW or 28.8%. After adjustment for a net import of 571 MW into the region, the total reserves are increased to 2,308 MW or 38.3%.

Historically, scheduled maintenance outages during the 1977-1979 winter peak periods have averaged 6.5% of installed capability. Adjusting for the capability unavailable because of maintenance during the winter peak period (503 MW), based on the average historical rate, the reserve margin is projected to be 1,798 MW or 29.9%. Full forced outages historically amounted to 2.6% of the installed winter capability and other unavailable capacity averaged 6.1%. Based on the historical rate, full forced outages are estimated to be 201 MW, thereby reducing the reserve margin to 1,597 MW or 26.6%. Adjusting for other unavailable capacity reduces the projected actual reserves to 1,125 MW or 18.7%, which are available for other contingencies and which should be adequate for reliability purposes.

Ghent No. 3, a 500 MW coal unit, is scheduled for service in August, 1981. This unit is not included in the summer 1981 planned capability but is included in the winter 1981 capability. If this unit is delayed beyond the 1981 winter peak period, the reserve margin for winter 1981 would be reduced to 625 MW or 10.4%. This could still be considered adequate from a reliability standpoint. The current capability and reserve data for the 1981 winter season are shown in Table 1E.5.

Future Perspective

Tables 1E.6.1 and 1E.6.2 show the projected actual reserve margins for the region for the summer and winter periods of 1982-1990. These were determined using the 1977-1980 historical outage rates for scheduled maintenance, full forced outages, and other unavailable capability. Both the near-term (1982-1985) and the long-term (1986-1990) summer periods are projected to have positive actual reserves each year, ranging from 22.0% to 32.6% in the near-term and 23.0% to 34.4% in the long-term period.

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During the winter peak periods, both the near-term and long-term periods are projected to have positive actual reserves each year, ranging from 10.9% to 25.0% in the near-term and 18.4% to 23.3% in the long-term.

The projected reserves for the summer and winter peak periods should be adequate for reliability purposes. The reserve figures were determined using historical values for scheduled maintenance, full forced outages and other unavailable capability as a percentage of planned capability.

Energy requirements and demands over the projected period are given in Table 1E.1 and planned generating capability by type of fuel is given in Tables 1E.7.1 and 1E.7.2. Table 1E.8 lists major generating unit installations and removals during the projection period.

Table 1E.1
Historical and Projected Energy Demands and Load Factors
Kentucky Group (Region 15)

	Energy Requirements		Summer Demand		Winter Demand		Annual Load Factor
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	(%)
1977	28,010	-	5,031	-	4,904	-	63.6
1978	28,543	1.9	5,183	3.0	5,045	2.9	62.9
1979	29,240	2.4	5,449	5.1	5,040	-0.1	61.3
1980	31,243	6.9	5,847	7.3	5,458	8.3	60.8
% Growth 1977-80		3.7		5.1		3.6	
1981	32,230	3.2	6,049	3.5	6,012	10.2	60.8
1982	33,610	4.3	6,361	5.2	6,307	4.9	60.3
1983	35,040	4.3	6,661	4.7	6,683	6.0	59.9
1984	36,810	5.1	6,997	5.0	6,047	4.0	59.9
1985	38,760	5.3	7,432	6.2	7,361	6.0	59.5
% Growth 1981-85		4.4		4.9		6.2	
1986	40,100	3.5	7,729	4.0	7,648	3.9	59.2
1987	41,460	3.4	8,036	4.0	7,953	4.0	58.9
1988	42,930	3.5	8,364	4.1	8,280	4.1	58.4
1989	44,430	3.5	8,795	5.2	8,611	4.0	57.7
1990	45,870	3.2	9,043	2.8	8,957	4.0	57.9
% Growth 1986-90		3.4		4.0		4.0	
% Growth 1981-90		3.9		4.5		5.1	

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The 1981-1985 energy requirements are projected to grow at a compound rate of 4.4%; 3.4% for the period 1986-1990; and 3.9% overall (1981-1990).

The summer demand growth rates are projected to decrease from the historical growth rate of 5.1% to 4.9% in the 1981-1985 period and to 4.0% in the 1986-1990 period, with an overall 1981-1990 rate of 4.5%.

The winter demand growth rates are projected to increase to 6.2% in the 1981-1985 period compared with the historical rate of 3.6%. In the 1986-1990 period the winter demands are projected to increase at the same rate as the summer demands, 4.0%. The overall growth rate for the 1981-1990 period of 5.1% is greater than that for the summer demands (4.5%). The annual load factors decrease from 60.8% in 1980 to 57.9% in 1990 due to the greater growth rate of the peak demand with respect to the energy requirements.

The summer capability by type of fuel use for the years 1981, 1985 and 1990 is given below.

Table 1E.2
Planned Summer Generating Capability by Type of Fuel
Kentucky Group (Region 15)

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			ST	CT	IC	ST	CT	IC	Conv.	P.S.	
1981											
MW	-	6,946	64	131	2	-	92	-	88	-	7,323
% Total	0.0	94.8	0.9	1.8	0.0	0.0	1.3	0.0	1.2	0.0	100.0
1985											
MW	-	9,113	64	131	2	-	92	-	88	-	9,490
% Total	0.0	96.0	0.7	1.4	0.0	0.0	1.0	0.0	0.9	0.0	100.0
1990											
MW	-	11,748	64	196	2	-	92	-	88	-	12,190
% Total	0.0	96.4	0.5	1.6	0.0	0.0	0.8	0.0	0.7	0.0	100.0

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There are currently no nuclear reactors installed in the region nor are any planned during the 1981-1990 period. There are, however, several coal units planned for installation during the period. The following table shows the amount of new generating capacity scheduled to be in service during each season and the effect on the projected reserve margins if these units are delayed beyond the peak occurrence of the season.

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Table 1E.3
Effect of Delay of New Units on Reserve Margins
Kentucky Group (Region 15)

	1982		1983		1984		1985	
	S	W	S	W	S	W	S	W
Reserves (MW)	2,035	1,236	1,617	726	1,539	1,661	2,426	1,839
Scheduled Capacity (MW)	495	-	-	-	-	895	600	890
Reserves - Scheduled Capacity (MW)	1,540	1,236	1,617	726	1,539	766	1,826	949
Reserves (%)	24.2	19.6	24.3	10.9	22.0	11.0	24.6	12.9

	1986		1987		1988		1989		1990	
	S	W	S	W	S	W	S	W	S	W
Reserves (MW)	2,491	1,534	2,166	1,692	2,420	1,930	3,023	2,005	2,762	1,646
Scheduled Capacity (MW)	-	-	-	600	-	650	-	495	-	-
Reserves - Scheduled Capacity (MW)	2,491	1,534	2,166	1,092	1,092	2,420	1,280	3,023	2,762	1,686
Reserves (%)	32.2	20.1	27.0	13.7	28.9	15.5	34.4	17.5	30.5	18.4

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In addition to the reserve capability available from existing and planned generating capacity additions within the region during the period, emergency power can also be supplied through existing and planned high voltage interconnections with other regions. Table 1E.4 lists the proposed bulk power lines planned from January 1, 1981-January 1, 1991.

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Table 1E.4
Kentucky Group (Region 15)
List of Proposed Bulk Power Lines - 01/01/81 to 01/01/91

Line Ownership List	Terminals	Length Miles	Expected Service Date	Voltage in KV Oper	Voltage in KV Design
	Interconnections				
PSI KU	Marble Hill Ghent[1]	40.5	May 81	345	345
KU	Pocket/Phipps Bend	24.0	Nov 81	500	500
PSI LG&E	Speed/Northside[2]	7.0	Jun 84	345	345
EKPC KU	Brodhead/Brown-Alcalde[3]	10.0	Aug 87	345	345
TVA KU	Volunteer/Pineville	45.0	Nov 87	500	500
IP&L KU	Patroit/Ghent[4]	20.0	Oct 89	345	345
	East Kentucky Power Cooperative				
EKPC	Avon/J.K. Smith	20.0	Dec 83	345	345
EKPC	J.K. Smith/Haggard	60.0	Jan 85	345	345
EKPC	J.K. Smith/Brodhead	40.0	Nov 85	345	345
	Kentucky Utilities Company				
KU	Brown/Hardin Co.[5]	70.0	Apr 82	345	345
KU	Smith/Hardin Co.[6]	65.0	Apr 82	345	345
KU	Pocket/Pineville	44.0	Nov 83	500	500
KU	Ghent/West Frankfort	40.0	Jul 84	345	345
KU	Brown/Pineville[7]	102.5	Nov 84	345	345
KU	Hanson/Smith	47.0	May 86	345	345
KU	Hancock/Smith-Hardin Co.[8]	10.0	Aug 88	345	345
KU	Hancock/Green River	46.0	Dec 90	345	345
KU	Hancock/Hardin Co.	50.0	Dec 90	345	345
KU	Hanson/Green River	24.0	Dec 90	345	345

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[1] Convert 138 kV D/C between Madison & Marble Hill to 1-138 kv Ck. Convert Madison-Ghent 138 kV to 345 kV. Provide area protection.

[2] Provide area protection.

[3] 10 mile D/C to loop Brodhead into Brown-Alcalde.

[4] Increase interchange capability; IP&L - Indianapolis Power & Light Co.

[5] Via Lebanon

[6] Convert from 138 kV

[7] 2nd CKT via Alcalde Station.

[8] Loop into Hancock on D/C towers.

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Table 1E.4 (continued)

Louisville Gas & Electric Company

LG&E	Blue Lick/Hill Creek	12.0	Jun 81	345	345
LG&E	Blue Lick/Middletown	19.0	Jun 81	345	345
LG&E	Trimble Co./Middletown- Clifty Creek	0.0	May 85	345	345
LG&E	Seatonville/Mill Ck. - Middletown 9/	0.0	May 85	345	345
LG&E	Trimble Co./Northside	26.0	May 89	345	345

9/ Take existing Mill Creek-Middletown 345 kV in and out of Seatonville

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Table 1E.5
Current Capability (MW) and Reserves (MW and Percent)
Kentucky Group (Region 15)

		1981/82 Winter Peak
1.	Planned Capability	7742
2.	Peak Demand	6012
3.	Planned Reserves (1-2)	1730
4.	Planned Reserves (%) (3/2)X100	28.8
5.	Net Transactions (Imports-Exports)	571
6.	Total Capability (1+5)	8313
7.	Total Reserves (6-2)	2301
8.	Total Reserves (%) (7/2)X100	38.3
9.	Scheduled Maintenance	503
10.	Capability After Maintenance	7810
11.	Reserves After Maintenance (10-2)	1798
12.	Reserves after Maintenance (%) (11/2)X100	29.9
13.	Full Forced Outages	201
14.	Capability After Full Forced Outages (10-13)	7609
15.	Reserves After Full Forced Outages (14-2)	1597
16.	Reserves (%) After Full Forced Outages (15/2)X100	26.6
17.	Other Unavailable Capability	472
18.	Actual Capability (14-17)	7137
19.	Actual Reserves (18-2)	1125
20.	Actual Reserves (%) (19/2)X100	18.7

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TABLE 1E.6.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
KENTUCKY GROUP (REGION 15)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	8309	8231	8239	8160	8567	9587	9982	10297
2. PEAK DEMAND	6361	6307	6661	6683	6997	6947	7432	7361
3. PLANNED RESERVES (1-2)	1948	1924	1578	1477	1570	2640	2550	2936
4. PLANNED RESERVES (%) (3/2)X100	30.6	30.5	23.7	22.1	22.4	38.0	34.3	39.9
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	577	563	526	489	475	478	465	468
6. TOTAL CAPABILITY (1+5)	8886	8794	8765	8649	9042	10065	10447	10765
7. TOTAL RESERVES (6-2)	2525	2487	2104	1966	2045	3118	3015	3404
8. TOTAL RESERVES (%) (7/2)X100	39.7	39.4	31.6	29.4	29.2	44.9	40.6	46.2
9. SCHEDULED MAINTENANCE /1/	66	535	66	530	65	623	80	669
10. CAPABILITY AFTER MAINTENANCE	8820	8259	8699	8119	8973	9442	10367	10096
11. RESERVES AFTER MAINTENANCE (10-2)	2459	1952	2038	1436	1976	2495	2935	2735
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	38.7	30.9	30.6	21.5	28.2	35.9	39.5	37.2
13. FULL FORCED OUTAGES /1/	158	214	157	212	163	249	190	268
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	8662	8045	8542	7907	8810	9193	10177	9828
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2301	1738	1881	1224	1813	2246	2745	2467
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	36.2	27.6	28.2	18.3	25.9	32.3	36.9	33.5
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	266	502	264	498	274	585	319	628
18. ACTUAL CAPABILITY (14-17)	8396	7543	8278	7409	8536	8608	9858	9200
19. ACTUAL RESERVES (18-2)	2035	1236	1617	726	1539	1661	2426	1839
20. ACTUAL RESERVES (%) (19/2)X100	32.0	19.6	24.3	10.9	22.0	23.9	32.6	25.0

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TABLE 2E.6.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990
KENTUCKY GROUP (REGION 15)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	10377	10297	10377	10097	11042	11612	12187	12107	12107	12107
2. PEAK DEMAND	7729	7648	8036	7553	8364	8280	8795	8611	9043	8957
3. PLANNED RESERVES (1-2)	2648	2649	2341	2544	2678	3332	3392	3496	3144	3150
4. PLANNED RESERVES (%) (3/2)X100	34.3	34.6	29.1	37.0	32.0	40.2	38.6	40.6	34.8	35.2
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	455	450	437	404	393	363	350	350	327	337
6. TOTAL CAPABILITY (1+5)	10832	10747	10814	11301	11435	11975	12537	12457	12524	12444
7. TOTAL RESERVES (6-2)	3103	3099	2778	3248	3071	3695	3742	3846	3481	3487
8. TOTAL RESERVES (%) (7/2)X100	40.1	40.5	34.6	42.1	36.7	44.6	42.5	44.7	38.5	38.9
9. SCHEDULED MAINTENANCE /1/	83	669	83	708	88	755	97	787	97	787
10. CAPABILITY AFTER MAINTENANCE	10749	10078	10731	10592	11347	11220	12440	11670	12427	11657
11. RESERVES AFTER MAINTENANCE (10-2)	3020	2430	2695	2640	2983	2940	3645	3059	3384	2700
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	39.1	31.8	33.5	35.2	35.7	35.5	41.4	35.5	37.4	30.1
13. FULL FORCED OUTAGES /1/	197	268	197	283	210	302	232	315	232	315
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	10552	9810	10534	10310	11137	10918	12208	11355	12155	11342
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2823	2162	2498	2757	2773	2638	3413	2744	3152	2385
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	36.5	28.3	31.1	25.6	33.2	31.9	38.8	31.9	34.9	26.6
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	332	628	332	665	353	708	390	739	350	739
18. ACTUAL CAPABILITY (14-17)	10220	9182	10202	9645	10784	10210	11818	10616	11805	10603
19. ACTUAL RESERVES (18-2)	2491	1534	2166	1692	2420	1930	3023	2005	2762	1646
20. ACTUAL RESERVES (%) (19/2)X100	32.2	20.1	27.0	21.3	28.9	23.3	34.4	23.3	30.5	18.4

BASED ON FORM ERA-411

TABLE 15.7.1

INSTALLED NET SUMMER CAPABILITY BY TYPE, AS OF MAY 31 - MW

KENTUCKY GROUP (REGION 15)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	0	6576	64	131	2	0	92	0	88	0	6953
% TOTAL	0.0	94.6	0.9	1.9	0.0	0.0	1.3	0.0	1.3	0.0	100.0
SUMMER 1981	0	6946	64	131	2	0	92	0	88	0	7323
% TOTAL	0.0	94.8	0.9	1.8	0.0	0.0	1.3	0.0	1.2	0.0	100.0
SUMMER 1982	0	7935	64	131	2	0	92	0	88	0	8312
% TOTAL	0.0	95.4	0.8	1.6	0.0	0.0	1.1	0.0	1.1	0.0	100.0
SUMMER 1983	0	7865	64	131	2	0	92	0	88	0	8242
% TOTAL	0.0	95.4	0.8	1.6	0.0	0.0	1.1	0.0	1.1	0.0	100.0
SUMMER 1984	0	7798	64	131	2	0	92	0	88	0	8175
% TOTAL	0.0	95.4	0.8	1.6	0.0	0.0	1.1	0.0	1.1	0.0	100.0
SUMMER 1985	0	9113	64	131	2	0	92	0	88	0	9490
% TOTAL	0.0	96.0	0.7	1.4	0.0	0.0	1.0	0.0	0.9	0.0	100.0
SUMMER 1986	0	10003	64	131	2	0	92	0	88	0	10380
% TOTAL	0.0	96.4	0.6	1.3	0.0	0.0	0.9	0.0	0.8	0.0	100.0
SUMMER 1987	0	10003	64	131	2	0	92	0	88	0	10380
% TOTAL	0.0	96.4	0.6	1.3	0.0	0.0	0.9	0.0	0.8	0.0	100.0
SUMMER 1988	0	10603	64	131	2	0	92	0	88	0	10980
% TOTAL	0.0	96.6	0.6	1.2	0.0	0.0	0.8	0.0	0.8	0.0	100.0
SUMMER 1989	0	11253	64	196	2	0	92	0	88	0	11695
% TOTAL	0.0	96.2	0.5	1.7	0.0	0.0	0.8	0.0	0.8	0.0	100.0
SUMMER 1990	0	11748	64	196	2	0	92	0	88	0	12190
% TOTAL	0.0	96.4	0.5	1.6	0.0	0.0	0.8	0.0	0.7	0.0	100.0

BASED ON FORM ERA-411

TABLE 1E.7.2

INSTALLED NET WINTER CAPABILITY BY TYPE OF FUEL, AS OF NOV.30 - MW

KENTUCKY GROUP (REGION 15)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	0	6605	65	143	2	0	0	0	67	0	6882
% TOTAL	0.0	96.0	0.9	2.1	0.0	0.0	0.0	0.0	1.0	0.0	100.0
WINTER 1981	0	7473	65	143	2	0	0	0	67	0	7750
% TOTAL	0.0	96.5	0.8	1.8	0.0	0.0	0.0	0.0	0.9	0.0	100.0
WINTER 1982	0	7962	65	143	2	0	0	0	67	0	8239
% TOTAL	0.0	96.7	0.8	1.7	0.0	0.0	0.0	0.0	0.8	0.0	100.0
WINTER 1983	0	7891	65	143	2	0	0	0	67	0	8168
% TOTAL	0.0	96.6	0.8	1.8	0.0	0.0	0.0	0.0	0.8	0.0	100.0
WINTER 1984	0	8718	65	143	2	0	0	0	67	0	8995
% TOTAL	0.0	97.0	0.7	1.6	0.0	0.0	0.0	0.0	0.7	0.0	100.0
WINTER 1985	0	9633	65	143	2	0	0	0	67	0	9910
% TOTAL	0.0	97.2	0.7	1.4	0.0	0.0	0.0	0.0	0.7	0.0	100.0
WINTER 1986	0	10028	65	143	2	0	0	0	67	0	10305
% TOTAL	0.0	97.3	0.6	1.4	0.0	0.0	0.0	0.0	0.7	0.0	100.0
WINTER 1987	0	10628	65	143	2	0	0	0	67	0	10905
% TOTAL	0.0	97.5	0.6	1.3	0.0	0.0	0.0	0.0	0.6	0.0	100.0
WINTER 1988	0	11278	65	208	2	0	0	0	67	0	11620
% TOTAL	0.0	97.0	0.6	1.8	0.0	0.0	0.0	0.0	0.6	0.0	100.0
WINTER 1989	0	11773	65	208	2	0	0	0	67	0	12115
% TOTAL	0.0	97.2	0.5	1.7	0.0	0.0	0.0	0.0	0.6	0.0	100.0
WINTER 1990	0	11773	65	208	2	0	0	0	67	0	12115
% TOTAL	0.0	97.2	0.5	1.7	0.0	0.0	0.0	0.0	0.6	0.0	100.0

BASED ON FORM ERA-411

Table 1E.8
Major Future Generating Capability Installations and Removals
Kentucky Group (Region 15)

System	Station	Unit Type 1/	Fuel Type 2/	Net Summer Capability (MW)	Net Winter Capability (MW)	In-Service Date 04/01/80 Report	In-Service Date 04/01/81 Report
EKPC	H.L. Spurlock #2	ST	COL	484	484	1/81	3/81
KU	Ghent #3	ST	COL	500	500	6/81	8/81
LG&E	Mill Creek #4	ST	COL	495	495	6/81	3/82
BIRI	D.B. Wilson #2	ST	COL	395	395	7/84	7/84
KU	Ghent #4	ST	COL	500	500	1/83	10/84
EKPU	J.K. Smith	ST	COL	600	600	1/85	1/85
LG&E	Trimble Co. #1	ST	COL	495	495	6/84	6/85
LG&E	Cane Run #2 & #3	ST	COL	-180	-180	6/85	6/85
BIRI	D.B. Wilson #2	ST	COL	395	395	1/86	1/86
FKPC	J.K. Smith	ST	COL	600	600	1/86	1/87
KU	Hancock Co. #1	ST	COL	650	650	10/87	10/88
LG&E	Trimble Co. #2	ST	COL	495	495	6/88	6/89

1/ ST = Steam
2/ COL = Coal

BASED ON FORM ERA-411

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INDIANA GROUP
ELECTRIC REGION 16

Electric Region 16, the Indiana Group, consists of the following Indiana electric systems: Hoosier Energy Division, Indiana Statewide Rural Electric Cooperative, Inc.; Indianapolis Power and Light Co.: Northern Indiana Public Electric Cooperative, Inc.; Indianapolis Power and Light Co.: Northern Indiana Public Service Co.; Public Service Co. of Indiana; Richmond, Indiana Municipal; and Southern Indiana Gas and Electric Co. The Indiana Group does not include the Indiana and Michigan Electric Co., which is part of the AEP system, (Electric Region 2), and the Indiana-Kentucky Corporation--a subsidiary of OVEC, which owns a 1300 MW generating plant at Madison, Indiana.

All of the included systems are regular or liaison members of the ECAR organization. Among the liaison members are the Wabash Valley Power Association (WVPA), formed in 1963 to represent its member systems in all wholesale power cost matters. Its membership consists of 22 distribution cooperatives, all but two of which are in Indiana. The WVPA has a 17 percent interest (192 MW) in the Marble Hill nuclear plant (1130 MW) under construction by the Public Service Company of Indiana and scheduled to come on line in December 1986. WVPA has scheduled the delivery of its share of the unit to Northern Indiana Public Service of Indiana; the loads of the WVPA member cooperatives are included in the load data of those two companies.

Historical Perspective

Table 1F.3 presents historic energy and demand statistics with their respective growth rates for the period 1977 to 1980. The Indiana Group has historically been a summer peaking system. Annual load factors for the system are also presented for the 1977 to 1980 period.

The utilities in the Indiana Region serve about 1.3 million customers, of which 1.1 million are residential customers; 135,000 are commercial customers; and 13,000 are industrial customers. The major transmission voltage in the region is 138-kV, with 345-kV ties to the Indiana and Michigan Electric Co. and the Commonwealth Edison Co., (Electric Region 6). There are also transmission ties with the Big Rivers Electric Corporation and the Louisville Gas and Electric Co. in the Electric Region 15.

Current Perspective

The 1981 expected summer load and supply situation for Electric Region 16 is given in Appendix C. As Table 1F.3 shows, winter demand is projected to show a marked increase from an average rate of 0.5 percent for the 1977-1980 period and 5.8 percent for winter, 1980 alone to 10.2 percent for the 1981-1982 winter period. The region is projected to change from an historically summer peaking region to a winter peaking region in 1981.

In Table 1F.1 the 1981-1982 winter planned capability is estimated to be 12,336 MW and the peak demand is projected to be 9151 MW, resulting in planned reserves of 3185 MW or 34.8 percent. After adjustment for a new import of 320 MW into the region, the total reserve is increased to 3505 MW or 38.3 percent.

Table 1F.1

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT)
INDIANA GROUP (REGION 16)

		1981/82 Winter Peak
1.	Planned Capability	12336
2.	Peak Demand	9151
3.	Planned Reserves (1-2)	3185
4.	Planned Reserves (%) (3/2/100)	34.8
5.	Net Transactions (Imports-Exports)	320
6.	Total Capability (1 + 5)	12656
7.	Total Reserves (6-2)	3505
8.	Total Reserves (%) (7/2)x100	38.3
9.	Scheduled Maintenance 1/	851
10.	Capability After Maintenance	11805
11.	Reserves After Maintenance (10-2)	2654
12.	Reserves After Maintenance (%) (11/2)x100	29.0
13.	Full Forced Outages 1/	913
14.	Capability After Full Forced Outages (10-13)	10892
15.	Reserves After Full Forced Outages (14-2)	1741
16.	Reserves (%) After Full Forced Outages (15/2)x100	19.0
17.	Other Unavailable Capability 1/ 2/	814
18.	Actual Capability (14-17)	10892
19.	Actual Reserves (18-2)	927
20.	Actual Reserves (%) (12/2)x100	10.1

1/ Scheduled maintenance, other unavailable capability and full forced outages are calculated using the historical percent averages at the time of the winter peaks beginning with the 1977 winter.

2/ Other unavailable capability is that capability which is unavailable for load for reasons other than scheduled maintenance or full forced outages.

Scheduled maintenance outages during the 1977-1979 winter peak periods averaged 6.9 percent of installed capability. Adjusting for the estimated capability unavailable because of maintenance during the winter peak period (851 MW based on the historical record), the projected reserve margin is reduced to 2654 MW or 29.0 percent. Full forced ottages historically have amounted to 6.6 percent of the installed winter capability and other unavailable capacity has averaged 6.6 percent. Based on this historical rate, full forced outages are estimated to be 913 MW, thereby reducing the reserve margin to 1741 MW or 19.0 percent. Adjustments for other unavailable capacity reduces the projected actual reserve to 924 MW or 10.1 percent, available for other contingencies.

There is a 450 MW coal unit scheduled for service in October 1981, which is recognized in the winter 1981 planned capability. If this coal unit were to be delayed beyond the 1981 winter peak period, the reserve margin for winter 1981 would be reduced to 477 MW or 5.2 percent. Reserves would still be reasonable relative to covering other contingencies.

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As part of the preparation for the April 1, 1981 ERA Form 411 on ECAR, member systems participated in the appraisal of anticipated transmission system performance for summer 1980 and winter 1980-81. These studies indicate that the outage of the Greentown 765/138 kV transformer (PSI) may for certain system conditions overload the 138 kV winding of the Kokomo 230/138/69kV transformer. To remedy this situation the following operating procedure has been established - upon loss of the Greentown 765/138 kV transformer, the Greentown 138 kV bus is split, isolating the PSI 138 kV circuits from the IME 138 kV circuits. To further reduce the Kokomo transformer loading, the Miami-Wabash peaking generation (70 MW) may be placed on line.

The April 1, 1981 ERA 411 report provides for a listing of critical bulk power transmission facilities that will not be in service when required. In this regard, ECAR reported that the Public Service of Indiana's Gibson to Dresser to Cayuga 345 kV transmission line has been delayed from its scheduled in-service date of December 31, 1977 to a tentative in-service date of June 30, 1981 due to litigation proceedings to acquire the right of way. The Gibson to Merom 345 kV section was placed in-service in November 1980.

Future Perspective

Table 1F.4 presents projected actual reserve margins for the Indiana Group over the 1982-1990 period. The actual reserves are based on the 1977-1980 historic outage rates for scheduled maintenance, full forced outages, and other unavailable capability. Both the near-term (1982-1985) and the long-term (1986-1990) summer periods are projected to have positive actual reserves each year, ranging from 10.5 to 14.8 percent in the near-term and 10.9 to 22.5 percent in the long-term period. Summer reserves thus seem adequate to cover unforeseen contingencies.

During the winter peak periods both the near-term and long-term periods are projected to have positive actual reserves each year, ranging from 7.7 to 13.7 percent in the near-term and 12.3 to 18.0 percent in the long-term period. Thus, winter reserves should be adequate to cover unforeseen contingencies. The reserve figures were determined using historic values for scheduled maintenance, full forced outages and other unavailable capability as a percent of planned capability.

The reserves' determination is dependent upon the peak load forecast and the planned capability. Projections of energy requirements and loads over the period of 1982 to 1990 are given in Table 1F.3. Planned generating capability by type of fuel and season is given in Table 1F.5. Table 1F.6 lists major generation additions and retirements over the 1982-1990 period.

Table 1F.3 indicates that energy requirements over the 1981-1985 period are projected to grow at a compound rate of 3.9 percent; over the 1986-1990 period, 3.8 percent; and over the combined period of 1981-1990, 3.9 percent.

With respect to summer demand a growth rate of 3.6 percent is projected for the 1981-85 period and a rate of 3.5 percent is projected for the 1986-1990 period. Over the 1981-1985 period the winter demand growth rate is estimated at 5.8 percent. For the 1986-1990 period, however, a lower growth rate of 4.1 percent is estimated. The annual load factors decrease from 60.9 percent in 1980 to 59.5 percent in 1990 due to the substantial increase in peak demand relative to the energy requirements.

As Table 1F.5 indicates, the Indiana Group currently has no nuclear reactors installed in the region. However, Table 1F.6 shows Public Service Company of Indiana's Marble Hill Plant Unit 1 (1130 MW) is scheduled for service in December 1986 with a second unit (1130 MW), scheduled for service in December 1987. In addition, the Northern Indiana Public Service Company's Bailly nuclear unit 1 (644 MW) is scheduled for operation in June 1989 despite a long history of delays. By 1990, 15.4 percent of the system capacity will be provided by nuclear generation.

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Tables 1F.5 and 1F.6 also show several coal-fired units planned for installation during the 1982-1990 period. Coal as a percent of capacity will be reduced from 90.1 percent to 78.8 percent.

Table 1F.2 shows the effect on reserve margins if each unit of new capacity scheduled for addition over the 1982-1990 period is delayed by one season. With the exception of the 1984 to 1986 winter period reserves appear to be adequate throughout the 1982-1990 period despite the capacity delays.

Table 1F.2

Effect of Delay of New Units on Reserve Margin
Indiana Region

	1982		1983		1984		1985	
	S	W	S	W	S	W	S	W
Reserves (MW)	1074	1315	1474	1096	1087	817	1201	997
Scheduled Cap. (MW)	450	625	344	-	,	250	344	515
Reserves Minus Sched. Cap. (MW)	624	690	1130	1096	1087	567	857	482
Reserves (%)	6.5	7.2	11.3	10.9	10.5	5.4	8.0	4.4

	1986			1987		1988		1989		
Reserves (MW)	1208	1581	1926	2167	2244	1670	2773	1643	2299	1662
Scheduled Cap. (MW)	-	1130	-	1130	-	400	644	-		
Reserves Minus Sched. Cap. (MW)	1208	451	1926	1037	2244	1170	2129	1643	2299	1012
Reserves (%)	10.9	3.9	16.7	8.6	18.9	8.4	17.3	12.7	18.1	7.5

In addition to the region's reserve capability available from existing and planned capacity during the period, emergency power can be obtained through high voltage existing and planned interconnections with other regions. Table 1F.7 lists the proposed bulk power lines planned from 1981 to 1991.

In response to the ERA 411 report's request for the reporting of Light Load System Studies, ECAR reported the following:

> "Public Service Indiana is presently carrying out a study of expected system performance for holiday weekends (Memorial Day, July 4th, and Labor Day) and minimum load during the Spring and Summer of 1988. Load levels are simulated for the PSI system at 50% (2400 MW) and 35% (1680 MW) of 1988 Summer Peak demand."

The 50% load level is expected to be exceeded 80% of the time, while the 35% level is the minimum load expected. An export to NIPSCO of 226 MW is included to simulate that portion of Wabash Valley Power Association (WVPA)'s ownership of the Marble Hill generation which serves the WVPA load on NIPSCO's system.

The study is intended to determine the severity of steady state over-voltage conditions in the time period being studied, the adequacy of reactive compensation on the 765 kV system associated with Marble Hill and the determination of possible solutions to overvoltage conditions. Various generation dispatch combinations are being studied as well as the impact of various power factor levels on steady state overvoltage conditions. Stability performance of the Marble Hill generating plant for light load conditions will also be examined.

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TABLE 1F.3

HISTORICAL AND PROJECTED ENERGY, DEMANDS AND LOAD FACTORS

REGION 16 - INDIANA GROUP

	ENERGY REQUIREMENTS		SUMMER DEMAND		WINTER DEMAND		ANNUAL LOAD FACTOR
	(GWH)	GROWTH(%)	(MW)	GROWTH(%)	(MW)	GROWTH(%)	(%)
1977	46192	-	8340	-	8172	-	63.2
1978	46967	1.7	8359	0.2	8348	2.2	64.1
1979	48604	3.5	8654	3.5	7852	-5.9	64.1
1980	47594	-1.3	8577	3.7	8303	5.7	60.9
% GROWTH 1977-80		1.3		2.5		0.5	
1981	49500	3.1	9142	1.8	9151	10.2	61.7
1982	52110	5.3	9572	4.7	9565	4.5	62.0
1983	54180	4.0	9959	4.0	10054	5.1	61.3
1984	56120	3.6	10345	3.9	10561	4.7	60.5
1985	58170	3.7	10718	3.6	11032	4.5	60.2
% GROWTH 1981-85		3.9		3.6		5.8	
1986	61030	4.9	11115	3.7	11531	4.5	60.4
1987	63420	3.9	11503	3.5	12023	4.3	60.2
1988	65720	3.6	11898	3.4	12508	4.0	59.8
1989	67840	3.2	12301	3.4	12972	3.7	59.7
1990	70180	3.4	12720	3.4	13465	3.8	59.5
% GROWTH 1986-90		3.8		3.5		4.1	
% GROWTH 1981-90		3.9		3.5		5.0	

TABLE 1F.4

sheet 1 of 2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
INDIANA GROUP (REGION 16)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	12604	13411	13568	13755	13568	14005	14162	14832
2. PEAK DEMAND	9572	9595	9959	10084	10345	10561	10718	11032
3. PLANNED RESERVES (1-2)	3032	3816	3609	3671	3223	3444	3444	3800
4. PLANNED RESERVES (%) (3/2)X100	31.7	39.8	36.2	36.4	31.2	32.6	32.1	34.4
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	298	301	294	300	293	299	291	297
6. TOTAL CAPABILITY (1+5)	12902	13712	13862	14055	13861	14304	14453	15129
7. TOTAL RESERVES (6-2)	3330	4117	3903	3971	3516	3743	3735	4097
8. TOTAL RESERVES (%) (7/2)X100	34.8	42.9	39.2	39.4	34.0	35.4	34.8	37.1
9. SCHEDULED MAINTENANCE /1/	567	925	611	949	611	966	637	1023
10. CAPABILITY AFTER MAINTENANCE	12335	12787	13251	13106	13250	13338	13816	14106
11. RESERVES AFTER MAINTENANCE (10-2)	2763	3192	3292	3022	2905	2777	3098	3074
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	28.9	33.3	33.1	30.0	28.1	26.3	28.9	27.9
13. FULL FORCED OUTAGES /1/	731	992	787	1018	787	1036	821	1098
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	11604	11795	12464	12088	12463	12302	12995	13008
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2032	2200	2505	2004	2118	1741	2277	1976
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	21.2	22.9	25.2	19.9	20.5	16.5	21.2	17.9
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	958	885	1031	908	1031	924	1076	979
18. ACTUAL CAPABILITY (14-17)	10646	10910	11433	11180	11432	11378	11919	12029
19. ACTUAL RESERVES (18-2)	1074	1315	1474	1096	1087	817	1201	997
20. ACTUAL RESERVES (%) (19/2)X100	11.2	13.7	14.8	10.9	10.5	7.7	11.2	9.0

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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TABLE 1F.4

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990 sheet 2 of 2
INDIANA GROUP (REGION 16)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	14645	15962	15775	17092	16905	17592	18049	18147	17960	18797
2. PEAK DEMAND	11115	11531	11503	12023	11898	12508	12301	12972	12720	13465
3. PLANNED RESERVES (1-2)	3530	4431	4272	5069	5007	5084	5748	5175	5240	5332
4. PLANNED RESERVES (%) (3/2)X100	31.8	38.4	37.1	42.2	42.1	40.6	46.7	39.9	41.2	39.6
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	299	485	478	670	263	263	256	261	274	259
6. TOTAL CAPABILITY (1+5)	14944	16447	16253	17762	17168	17855	18305	18408	18234	19056
7. TOTAL RESERVES (6-2)	3829	4916	4750	5739	5270	5347	6004	5436	5514	5591
8. TOTAL RESERVES (%) (7/2)X100	34.4	42.6	41.3	47.7	44.3	42.7	48.8	41.9	43.3	41.5
9. SCHEDULED MAINTENANCE /1/	659	1101	710	1179	761	1214	812	1252	808	1297
10. CAPABILITY AFTER MAINTENANCE	14285	15346	15543	16583	16407	16641	17493	17156	17426	17759
11. RESERVES AFTER MAINTENANCE (10-2)	3170	3815	4040	4560	4509	4133	5192	4184	4706	4294
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	28.5	33.1	35.1	37.9	37.9	33.0	42.2	32.3	37.0	31.9
13. FULL FORCED OUTAGES /1/	849	1181	915	1265	980	1302	1047	1343	1042	1391
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	13436	14165	14628	15318	15427	15339	16446	15813	16384	16368
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2321	2634	3125	3295	3529	2831	4145	2841	3664	2903
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X1C	20.9	22.8	27.2	27.4	29.7	22.6	33.7	21.9	28.8	21.6
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	1113	1053	1199	1128	1285	1161	1372	1198	1365	1241
18. ACTUAL CAPABILITY (14-17)	12323	13112	13429	14190	14142	14178	15074	14615	15019	15127
19. ACTUAL RESERVES (18-2)	1208	1581	1926	2167	2244	1670	2773	1643	2299	1662
20. ACTUAL RESERVES (%) (19/2)X100	10.9	13.7	16.7	18.0	18.9	13.4	22.5	12.7	18.1	12.3

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

TABLE 1F.5 SHEET 1 OF 2

INSTALLED NET SUMMER CAPABILITY BY TYPE, AS OF MAY 31 - MW

INDIANA GROUP (REGION 16)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	0	10542	408	518	32	0	24	0	65	0	11589
% TOTAL	0.0	90.9	3.5	4.5	0.3	0.0	0.2	0.0	0.6	0.0	100.0
SUMMER 1981	0	10542	408	578	32	0	24	0	65	0	11649
% TOTAL	0.0	90.4	3.5	5.0	0.3	0.0	0.2	0.0	0.6	0.0	100.0
SUMMER 1982	0	11047	408	578	32	0	24	0	65	0	12154
% TOTAL	0.0	90.8	3.4	4.8	0.3	0.0	0.2	0.0	0.5	0.0	100.0
SUMMER 1983	0	12117	408	578	32	0	24	0	65	0	13224
% TOTAL	0.0	91.6	3.1	4.4	0.2	0.0	0.2	0.0	0.5	0.0	100.0
SUMMER 1984	0	12461	408	578	32	0	24	0	65	0	13568
% TOTAL	0.0	91.8	3.0	4.3	0.2	0.0	0.2	0.0	0.5	0.0	100.0
SUMMER 1985	0	12711	408	578	32	0	24	0	65	0	13818
% TOTAL	0.0	91.9	3.0	4.2	0.2	0.0	0.2	0.0	0.5	0.0	100.0
SUMMER 1986	0	13570	376	578	32	0	24	0	65	0	14645
% TOTAL	0.0	92.7	2.6	3.9	0.2	0.0	0.2	0.0	0.4	0.0	100.0
SUMMER 1987	1130	13570	376	578	32	0	24	0	65	0	15775
% TOTAL	7.2	85.9	2.4	3.7	0.2	0.0	0.2	0.0	0.4	0.0	100.0
SUMMER 1988	2260	13570	376	578	32	0	24	0	65	0	16905
% TOTAL	13.4	80.3	2.2	3.4	0.2	0.0	0.1	0.0	0.4	0.0	100.0
SUMMER 1989	2260	14070	376	578	32	0	24	0	65	0	17405
% TOTAL	13.0	80.8	2.2	3.3	0.2	0.0	0.1	0.0	0.4	0.0	100.0
SUMMER 1990	2904	14070	287	578	32	0	24	0	65	0	17960
% TOTAL	16.2	78.3	1.6	3.2	0.2	0.0	0.1	0.0	0.4	0.0	100.0

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TABLE 1F.5

SHEET 2 OF 2

INSTALLED NET WINTER CAPABILITY BY TYPE OF FUEL, AS OF NOV.30 - MW

INDIANA GROUP (REGION 16)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	0	10612	426	610	33	0	0	0	65	0	11746
% TOTAL	0.0	90.3	3.6	5.2	0.3	0.0	0.0	0.0	0.6	0.0	100.0
WINTER 1981	0	11117	426	695	33	0	0	0	65	0	12336
% TOTAL	0.0	90.1	3.5	5.6	0.3	0.0	0.0	0.0	0.5	0.0	100.0
WINTER 1982	0	12192	426	695	33	0	0	0	65	0	13411
% TOTAL	0.0	90.9	3.2	5.2	0.2	0.0	0.0	0.0	0.5	0.0	100.0
WINTER 1983	0	12536	426	695	33	0	0	0	65	0	13755
% TOTAL	0.0	91.1	3.1	5.1	0.2	0.0	0.0	0.0	0.5	0.0	100.0
WINTER 1984	0	12536	426	695	33	0	0	0	65	0	13755
% TOTAL	0.0	91.1	3.1	5.1	0.2	0.0	0.0	0.0	0.5	0.0	100.0
WINTER 1985	0	13645	426	695	33	0	0	0	65	0	1486[illegible]
% TOTAL	0.0	91.8	2.9	4.7	0.2	0.0	0.0	0.0	0.4	0.0	100.0
WINTER 1986	0	13645	394	695	33	0	0	0	65	0	14832
% TOTAL	0.0	92.0	2.7	4.7	0.2	0.0	0.0	0.0	0.4	0.0	100.0
WINTER 1987	1130	13645	394	695	33	0	0	0	65	0	15962
% TOTAL	7.1	85.4	2.5	4.4	0.2	0.0	0.0	0.0	0.4	0.0	100.0
WINTER 1988	2263	13645	394	695	33	0	0	0	65	0	17095
% TOTAL	13.2	79.8	2.3	4.1	0.2	0.0	0.0	0.0	0.4	0.0	100.0
WINTER 1989	2904	14145	394	695	33	0	0	0	65	0	18236
% TOTAL	15.9	77.5	2.2	3.8	0.2	0.0	0.0	0.0	0.4	0.0	100.0
WINTER 1990	2904	14795	385	695	33	0	0	0	65	0	18797
% TOTAL	15.4	78.8	1.6	3.7	0.2	0.0	0.0	0.0	0.3	0.0	100.0

TABLE 1F.6

Major Future Generating Capability Installations and Removals
Indiana Group (Region 16)

DOE/ERA Electric Region	System	Station	Unit Type	Fuel Type	Net Capability-MW Summer	Net Capability-MW Winter	In-Service Date 1/ 04/01/80 Report	In-Service Date 1/ 04/01/81 Report
6	HED	Merom #2	ST	Col	450	450	10/81	10/81
6	HED	Merom #1	ST	Col	450	450	7/82	7/82
6	PSI	Gibson #5	ST	Col	620	625	10/82	10/82
6	NIPS	R.M.Schahfer #17	ST	Col	344	344	6/83	6/83
6	SIGE	A.B.Brown #2	ST	Col	250	250	1/84	1/85
6	NIPS	R.M.Schahfer #18	ST	Col	344	344	6/85	6/85
6	IP&L	Petersburg #4	ST	Col	515	515	10/84	10/85
6	PSI	Marble Hill #1	NP 2/	UR	1130 4/	1130 4/	10/82	12/86
6	PSI	Marble Hill #2	NP 2/	UR	1130 4/	1130 4/	1/84	12/87
	SIGE	A.B. Brown #3	ST	Col	500	500	1/88	1/89
	NIPS	Bailly #1	NB 3/	UR	644	644	6/87	6/89
	IP&L	Patriot #1		Col	650	650	10/88	10/90

1/ Comparison of scheduled in-service dates in the April 1, 1980 and April 1, 1981 Regional Reliability Council Reports.

2/ Pressurized Water Reactor.

3/ Boiling Water Reactor.

4/ Jointly owned: PSI-938 MW; WVPA-192 MW.

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Table 1F.7
Indiana Group (Region 16)

List of Proposed Bulk Power Lines - 01/01/81 to 01/01/91

Line Ownership List		Terminals	Line Length Miles	Expected Service Date	Nominal Voltage in kV Oper	Design	Notes
		Interconnections					
HED	PSI	Ramsey/Gibson-Speed	0.0	May 81	345	345	Loop into Ramsey Provide Area Support
PSI	KU	Marble Hill/Ghent	40.5	May 81	345	345	Convert 138kV D/C Between Madison and Marble Hill to 1-138kV and 1-345kV Ck. Convert Madison-Ghent 138 kV to 345 kV Provide Area Protection
HED	PSI	Merom/Dresser	25.0	Jun 81	345	345	Deliver Generator Output
IP&L	PSI	Petersburg/Gibson-Bedford	10.0	Aug 82	345	345	Coordinated Agreement Loop into Petersburg Deliver Generator Output
PSI	LG&E	Speed/Northside	7.0	Jun 84	345	345	Provide Area Protection
IP&L	PSI	Sunnyside/Gwynneville	44.0	Aug 85	345	345	Coordinated Agreement Deliver Generator Output
AEP	PSI	Jefferson/Marble Hill	15.0	Nov 25	765	765	Date Change Deliver Generator Output
PSI	AEP	Gwynneville/Jefferson-Greentown	0.0	May 87	765	765	Date Change Loop into Gwynneville Deliver Generator Output
IP&L	KU	Patroit/Ghent	20.0	Oct 89	345	345	Deliver Generator Output
		Hoosier Energy					
	HED	Merom/Worthington	28.3	Mar 81	345	345	Deliver Generator Output
	HED	Worthington/Bloomington	31.7	Mar 81	345	345	Deliver Generator Output Increase Capability

Table 1F.7
Indiana Group (Region 16)

Sheet 2 of 2

List of Proposed Bulk Power Lines - 01/01/81 to 01/01/91

Line Ownership List	Terminals	Line Length Miles	Expected Service Date	Nominal Voltage in kV Oper	Nominal Voltage in kV Design	Notes
	Indianapolis Power & Light Company					
IP&L	Columbus/Gwynneville	26.0	Apr 82	345	345	Coordinated Agreement
IP&L	Stout/Hanna-Thompson	1.0	Apr 82	345	345	Relieve Overloads
IP&L	Patriot/Sunnyside	108.0	Oct 90	345	345	Transmission for New Generation
	Northern Indiana Public Service Company					
NIPS	Chicago Ave./Dune Acr-Sheffield	0.0	Jun 81	345	345	
NIPS	Stillwell/Babcock-Dumont (AEP)	0.0	Jun 81	345	345	
NIPS	Munster/Lake George-Burnham (CE)	0.0	Jun 82	345	345	
NIPS	Schahfer/St. John	40.0	Jun 83	345	345	
NIPS	Dune Acres/Miller	12.0	Jun 87	345	345	
NIPS	Miller/Green Acres	9.0	Jun 87	345	345	
NIPS	Leesburg/LaGrange	33.0	Jun 87	345	345	
NIPS	New Site/Schahfer	45.0	Jun 88	345	345	
NIPS	New Site/Reynolds	17.0	Jun 88	345	345	
NIPS	New Site/Burr Oak	50.0	Jun 88	345	345	
NIPS	Dune Acres/Lake George	19.0	Jun 89	345	345	
NIPS	Luchtman Road/Michigan City-Babcock	9.0	Jun 89	345	345	
	Public Service Co. of Indiana, Inc.					
PSI	Dresser/Cayuga	41.0	Nov 81	345	345	Deliver Generator Output
PSI	Koko Webster St./Greentown	20.0	Dec 81	230	230	Provide Area Support
PSI	Peru/Greentown	25.0	Dec 81	230	230	Provide Area Support
PSI	Gwynneville/Greensboro	24.0	May 82	345	345	Provide Area Support
PSI	Marble Hill/Columbus	52.0	Jun 84	765	765	Deliver Generator Output
PSI	Columbus/Gwynneville	40.0	May 87	765	765	Provide Area Protection

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MICHIGAN ELECTRIC COORDINATED SYSTEMS (MECS)

ELECTRIC REGION 18

Historical Perspective

Electric Region 18 consists of the electric systems in Lower Michigan excluding the American Electric Power System (AEP) subsidiary in the southwest corner and one system in the eastern corner of the state and one system in the eastern corner of Upper Michigan. The following systems are included in the data of this section: Consumers Power Co.; Detroit Edison Co.; Detroit, MI Public Lighting Department; Edison Sault Electric Co.; Lansing, Michigan Municipal; and the Michigan Municipal Cooperative Pool (MMCP).

All of the systems for which data are included in this section are regular or liaison members of the ECAR Council (East Central Area Reliability Coordination).

The Detroit Edison Company and Consumers Power Company are Michigan's two largest electric utility companies, serving about 90% of the state's population. In December 1962 the two companies entered into an Electric Power Pooling Agreement and in 1973 formed the Michigan Electric Coordinated Systems (MECS). The MECS agreement provides for mutual assistance and coordination of the expansion of generating and major transmission facilities. Also, operation and maintenance of electric facilities are coordinated for economy of operation as well as reliability of service. The Michigan Electric Power Coordination Center has been constructed at Ann Arbor, Michigan to facilitate the coordinated operation of the generation and transmission facilities of the two companies. Coordination with Ontario Hydro and other utilities is also conducted at the center.

The MMCP was established in 1968; the current members are: Conalco (Consolidated Aluminum Co.); Grand Haven, MI Municipal; Lowell, MI Municipal; Northern Michigan Electric Cooperative; Traverse City, MI Municipal; Wolverine Electric Cooperative; and Zeeland, MI Municipal. The objective of the pooling agreement is that the participants collectively provide capacity adequate to carry the total annual demands of all participants, with adequate reserve capacity, through the coordination of their planning and construction of additional generating and transmission facilities. MMCP operates a control center for economic dispatch of generating units.

Current Perspective

The 1981 expected summer load and supply situation for Electric Region 18 is given in Appendix C. The 1981-1982 winter situation is discussed below.

The 1981-1982 winter planned capability is estimated to be 16,332 MW and the peak demand is projected to be 10,928 MW, resulting in planned reserves of 5,404 MW or 49.5%. After adjustment for a net export of 561 MW out of the region, the total reserve is decreased to 4,843 MW or 48.3%.

Scheduled maintenance outages during the 1977-1979 winter peak periods averaged 5.4% of installed capability. Adjusting for the capability unavailable because of maintenance during the winter peak period (882 MW) based on the average historical rate, the reserve margin is projected to be 3,961 MW or 36.2%. Full forced outages historically amounted to 3.8% of the installed winter capability and other unavailable capacity averaged 9.3%. Based on the historical rate, full forced outages are estimated to be 621 MW, thereby reducing the reserve margin to 3340 MW or 30.6%. Adjusting for other unavailable capacity reduces the projected actual reserves to 1870 MW or 17.1%, which is available for other contingencies. The current capability and reserve data for the 1981 winter season are shown in Table 1G.5.

A wide range of postulated system conditions were considered during the course of various studies performed for Summer 1980 and Winter 1980-1981 conditions. The studies did not indicate a need in the MECS region for development of special operating procedures.

[redacted]

Table 1G.2 shows total MECS generating capability, segregated by type of fuel, for the summers of 1981, 1985, and 1990. Nuclear capacity is planned to increase from 4.4% of total generating capability in 1981 to 14.9% in 1990. Table 1G.7.1 shows the year-by-year changes in installed capability at the time of the summer peaks for 1981-1990 and Table 1G.7.2 shows the corresponding winter data.

Table 1G.2
Planned Summer Generating Capability by Type of Fuel
MECS Region

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			ST	CT	IC	ST	CT	IC	Conv.	P.S.	
1981											
MW	698	9,632	2,313	305	172	143	557	54	166	1,872	15,912
%Total	4.4	60.6	14.5	1.9	1.1	0.9	3.5	0.3	1.0	11.8	100.0
1985											
MW	3,080	10,354	3,311	305	172	29	557	60	166	1,872	19,906
%Total	15.5	52.1	16.6	1.5	0.9	0.1	2.8	0.3	0.8	9.4	100.0
1990											
MW	3,096	11,168	3,311	305	172	29	557	60	166	1,872	20,736
%Total	14.9	53.9	16.0	1.5	0.8	0.1	2.7	0.3	0.8	9.0	100.0

BASED ON FORM ERA-411.

There are currently two nuclear reactors installed in the region totaling 698 MW and three more are planned during the 1981-1990 period. There also are three coal units planned for installation during the period. The following table shows the amount of new capacity scheduled to be in service during each season and the effect on the reserve margins if these units were delayed beyond the time of seasonal peak load.

Table 1G.3
Effect of Delay of New Units on Reserve Margin
MECS Region

	1982		1983		1984		1985	
	S	W	S	W	S	W	S	W
Reserves (MW)	1,594	2,340	779	3,615	2,957	4,156	3,049	4,328
Scheduled Capacity (MW)	-	-	-	1,901	1,169	-	664	-
Reserves Minus Sched. Cap. (MW)	1,594	2,340	779	1,714	1,788	4,156	2,385	4,328
Reserves (%)	1,301	20.7	6.0	14.4	13.1	33.9	17.1	34.9

	1986		1987		1988		1989		1990	
	S	W	S	W	S	W	S	W	S	W
Reserves (MW)	2,926	4,091	2,585	3,239	1,433	3,134	1,353	3,450	1,520	3,154
Scheduled Capacity (MW)	-	-	150	-	-	-	-	740*	-	-
Reserves Minus Sched. Cap. (MW)	2,926	4,091	2,435	3,239	1,433	3,134	1,353	2,710	1,520	3,154
Reserves (%)	20.5	31.8	16.5	24.5	9.3	23.0	8.6	19.5	9.4	22.2

*Palisades #1 nuclear unit scheduled to return to service after replacement of steam generator.

BASED ON FORM ERA-411.

[redacted]

It can be seen from the above table that there would still be adequate reserves each season even if the new units were delayed beyond the peak occurrence. Table 1G.8 lists the major capacity changes scheduled for the region.

The reserve capability of the region is influenced by the transfer capability of its transmission system. Tables 1G.4.1 and 1G.4.2 list the proposed bulk power lines planned for the period Jaunuary 1, 1981 - January 1, 1991. The April 1, 1981 ERA-411 report requested each Reliability Council to report critical bulk power transmission facilities that will not be in service when required. The following was reported by ECAR:

> "The Manning 345/138 kV bulk power transmission station was planned to be cut into the existing Consumers Power Company Tittabawassee to Thetford 345 kV line east of Saginaw, Michigan during the summer of 1982. It provides an adequate level of reliability to the load areas of Saginaw and Bay City. This facility has been delayed until late 1983 because of the Company's inability to raise funds due to inadequate and untimely rate relief. The Manning Station is required to maintain adequate transmission system voltages. During certain postulated transmission station outages, voltages on the 138 kV system could drop low enough to cause generating plant auxiliary equipment to be lost, thus resulting in the subsequent tripping of generating units. Tests indicate a potential for cascading power interruptions as a result of this generator unit tripping."

Also, in response to the ERA-411 request to discuss light load system analysis studies, the following was reported:

> "During the first half of 1980, Detroit Edison conducted a study for expected 1982-1989 conditions to determine if the operation of the new Belle River Units 1 and 2 and Enrico Fermi 2 nuclear unit at full load would cause operating problems with other base loaded fossil units during light load periods. Of particular concern was system voltage levels for a 3000 MW system load level (approximately 45% of Detroit Edison's 1980 summer peak demand). Detroit Edison transactions with neighboring utilities were assumed to be zero. Results of the study indicate that acceptable voltage levels can be maintained by utilizing the available reactive supply."

Table 1G.8

Major Projected Capacity Changes

Michigan Electric Coordinated Systems (Region 18)

System 1/	Unit	Type 2/	Fuel 3/	Capability (MW) Summer	Capability (MW) Winter	Scheduled Date 4/ 4/80	Scheduled Date 4/ 4/81
CP	Midland 2	NP	Ur	783	807	9/84	12/83
DE	Fermi 2	NB	Ur	1094	1094	3/82	12/83
DE	Belle Rvr 1	St	Col	664	664	3/84	7/84
CP	Midland 1	NP	Ur	505	522	3/85	7/84
DE	Belle Rvr 2	St	Col	664	664	3/85	7/85
LBWL	Erickson 2	St	Col	150	150	3/86	3/87
CP	Palisades 1	NP	Ur	(635)5/	(740)5/	8/87	8/87
CP	Palisades 1	NP	Ur	635 5/	740 5/	8/89	8/89

1/ CP = Consumers Power Company; DE = Detroit Edison Company;
LBWL = Lansing Board of Water and Light.

2/ NB = Boiling Water Reactor; NP = Pressurized Water Reactor;
ST = Steam

3/ Ur = Uranium; Col = Coal

4/ Comparison projected operating dates as reported in the April 1, 1980 and April 1, 1981 ERA-411 reports.

5/ Palisades #1 will be taken out of service for 2 years for replacement of the steam generator.

Future Perspective

The projected actual reserve margins of the region for the summer and winter periods of 1982-1990 were determined using the 1977-1980 historical outage rates for scheduled maintenance, full forced outages, and other unavailable capability (see Tables 1G.6.1 and 1G.6.2). Both the near-term (1982-1985) and the long-term (1986-1990) summer periods are projected to have positive actual reserves each year, ranging from 6.0% to 21.9% in the near-term and 8.6% to 20.5% in the long-term period. (Minor changes to the ERA-411 net transactions data for the 1985 summer and 1985-1986 winter periods were reported by ECAR in a June 12, 1981 letter. This data was received too late to incorporate into this report. These changes, however, would have no significant effect on the data presented on Tables 1G.6.1 and 1G.6.2.)

During the winter peak periods, both the near-term and long-term period are projected to have positive actual reserves each year, ranging from 20.7% to 34.9% in the near-term and 22.2% to 31.8% in the long-term period. The projected actual reserves for both the summer and winter peak periods could be considered adequate for reliability purposes.

Energy requirements and demand for the historical and projected periods are given in Table 1G.1.

The 1981-1985 energy requirements are projected to grow at a compound rate of 3.8% annually, for 1986-1990 the rate is 3.1%. Summer peak period demand is projected to increase 0.9% annually in 1981 and 1982, 3.0% annually for 1981-1985 and also for 1986-1990 and 1981-1990. These growth rates are not too different from those projected for the other regions in ECAR. Winter peak period demand is projected to increase 0.6% in 1981, 2.7% annually in 1981-1985, 2.8% annually in 1986-1990 and 2.7% annually for the period 1981-1990.

TABLE 16.1

HISTORICAL AND PROJECTED ENERGY, DEMANDS AND LOAD FACTORS

REGION 18 - MICHIGAN ELECTRIC COORDINATED SYSTEMS (MECS)

	ENERGY REQUIREMENTS		SUMMER DEMAND		WINTER DEMAND		ANNUAL LOAD FACTOR
	(GWH)	GROWTH(%)	(MW)	GROWTH(%)	(MW)	GROWTH(%)	(%)
1977	70075	-	12645	-	11157	-	63.3
1978	71700	2.3	12652	0.1	11434	2.5	64.7
1979	72010	0.4	12018	-5.0	10872	-4.5	68.4
1980	65475	-9.1	11985	-0.3	10868	-0.0	62.2
% GROWTH 1977-80		-2.2		-1.8		-0.5	
1981	68480	4.6	12087	0.9	10528	0.6	64.7
1982	70340	2.7	12200	0.9	11283	3.2	65.8
1983	75060	6.7	13065	7.1	11508	5.5	65.6
1984	78400	4.4	13688	4.8	12263	3.0	65.2
1985	78750	0.4	13912	1.6	12387	1.0	64.6
% GROWTH 1981-85		3.8		3.0		2.7	
1986	81810	3.9	14275	2.6	12864	3.5	65.4
1987	84260	3.0	14742	3.3	13234	2.9	65.2
1988	87510	3.9	15357	4.2	13653	3.2	64.9
1989	89560	2.3	15751	2.6	13528	2.0	64.9
1990	91730	2.4	16137	2.5	14237	2.2	64.9
% GROWTH 1986-90		3.1		3.0		2.8	
% GROWTH 1981-90		3.4		3.0		2.7	

BASED ON FORM ERA-411

Table 1G.4.1

Michigan Electric Coordinated Systems (Region 18)

List of Proposed Bulk Power Lines - 01/01/81 to 01/01/91

Line Ownership List	Terminals	Line Length Miles	Expected Service Date	Nominal Voltage in kV		Notes
				Oper	Design	
	INTERCONNECTIONS					
CP DECO	GOSS / MADRID-PONTIAC	45.8	JUN 84	345	345	INCREASE INTERCHANGE CAPABILITY LOOP INTO GOSS
	CONSUMERS POWER COMPANY					
CP	TITTABAWASSEE / KENOWA-THETFORD	55.0	OCT 83	345	345	DELIVER GENERATOR OUTPUT LOOP INTO TITTABAWASSEE
CP	MIDLAND / TITTABAWASSEE	2.6	DEC 83	345	345	DELIVER GENERATOR OUTPUT UNIT #2
CP	MANNING / TITTABAWASSEE-THETFORD	0.1	DEC 83	345	345	PROVIDE AREA PROTECTION LOOP INTO MANNING
CP	POMPEII / KENOWA-TITTABAWASSEE	0.1	JUN 84	345	345	PROVIDE AREA PROTECTION TAP
CP	MIDLAND / TITTABAWASSEE	2.6	JUL 84	345	345	DELIVER GENERATOR OUTPUT UNIT #1
CP	PERE MARQUETTE / KEYSTONE	75.1	OCT 85	345	345	PROVIDE AREA PROTECTION
CP	ONEIDA / ARGENTA-MAJESTIC(DE)	19.3	JUN 86	345	345	PROVIDE AREA PROTECTION TAP
CP	BATTLE CREEK / ARGENTA-MAJESTIC (DE)	3.4	JUN 86	345	345	PROVIDE AREA PROTECTION LOOP INTO BATTLE CREEK, REMOVE TAP TO ARGENTA/THOMPKINS
CP	TIPSICO LK / GROSS-PONTIAC(DE)	0.4	JUN 87	345	345	PROVIDE AREA PROTECTION LOOP INTO TIPSICO LAKE
CP	GALLAHGER / LIVINGSTON-TITTABAWASSEE	0.1	NOV 89	345	345	PROVIDE AREA PROTECTION REMOVE TAP AND ADD LOOP INTO GALLAGHER
CP	GALLAGHER / ALPENA	89.6	NOV 90	345	345	PROVIDE AREA PROTECTION RADIAL

BASED ON FORM ERA-411

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Table 1G.4.2
Michigan Electric Coordinated Systems (Region 18)

List of Proposed Bulk Power Lines - 01/01/81 to 01/01/91

THE DETROIT EDISON COMPANY

Line Ownership List	Terminals	Line Length Miles	Expected Service Date	Nominal Voltage in kV		Notes
				Oper	Design	
DECO	FERMI / BROWNSTOWN NAVARRE	4.0	AUG 82	345	345	DELIVER GENERATOR OUTPUT
DECO	FERMI / BROWNSTOWN SUPERIOR	5.0	OCT 82	345	345	DELIVER GENERATOR OUTPUT
DECO	BROWNSTOWN NAVARRE / MONROE 3,4	0.0	OCT 82	345	345	CHANGE IN TERMINATION FOR FERMI
DECO	BROWNSTOWN SUPERIOR / MONROE 1,2	0.0	OCT 82	345	345	CHANGE IN TERMINATION FOR FERMI
DECO	HINES / WARREN	13.0	MAY 83	230	230	RELIEVE OVERLOADS CONVERT FROM 120 KV TO 230 KV
DECO	BISMARCK / STEPHENS	8.0	MAY 83	345	345	RELIEVE OVERLOADS
DECO	JEWELL / BISMARCK	9.0	MAY 83	345	345	RELIEVE OVERLOADS
DECO	BISMARCK / RED RUN	7.0	MAY 83	230	230	RELIEVE OVERLOADS CONVERT FROM 120 KV TO 230 KV
DECO	BELLE RIVER / ST. CLAIR-PONTIAC	0.0	JUN 83	345	345	DELIVER GENERATOR OUTPUT LOOP INTO BELLE RIVER
DECO	BELLE RIVER / GREENWOOD-JEWELL	0.0	JUN 83	345	345	DELIVER GENERATOR OUTPUT LOOP INTO BELLE RIVER
DECO	SARATOGA / BELLE RIVER-GREENWOOD	0.0	MAR 84	345	345	DELIVER GENERATOR OUTPUT LOOP INTO SARATOGA
DECO	SARATOGA / JEWELL	24.0	MAR 84	345	765	DELIVER GENERATOR OUTPUT
DECO	ARLINGTON / MONROE 1,2-WAYNE	3.0	MAY 84	345	345	RELIEVE OVERLOADS-LOOP INTO ARLINGTON
DECO	ARLINGTON / HINES	10.0	MAY 84	230	230	RELIEVE OVERLOADS CONVERT FROM 120 KV TO 230 KV.
DECO	COVENTRY / MAJESTIC-WAYNE	0.0	MAY 86	345	345	RELIEVE OVERLOADS LOOP INTO COVENTRY
DECO	WIXOM / NORTHWEST	18.0	MAY 88	230	230	RELIEVE OVERLOADS CONVERT FROM 120 KV TO 230 KV

BASED ON FORM ERA-411

Table 1G.5

Current Capability (MW) and Reserves (MW and Percent)
Michigan Electric Coordinated Systems Group (Region 18)

		1981/82 Winter Peak
1.	Planned Capability	16332
2.	Peak Demand	10928
3.	Planned Reserves (1-2)	5404
4.	Planned Reserves (%) (3/2) x 100	49.5
5.	Net Transactions (Imports-Exports)	-561
6.	Total Capability (1+5)	15771
7.	Total Reserves (6-2)	4843
8.	Total Reserves (%) (7/2) x 100	44.3
9.	Scheduled Maintenance	882
10.	Capability After Maintenance	14889
11.	Reserves After Maintenance (10-2)	3961
12.	Reserves After Maintenance (%) (11/2) x 100	36.2
13.	Full Forced Outages	621
14.	Capability After Full Forced Outages (10-13)	14268
15.	Reserves After Full Forced Outages (14-2)	3340
16.	Reserves (%) After Full Forced Outages (15/2) x 100	30.6
17.	Other Unavailable Capability	1470
18.	Actual Capability (14-17)	12798
19.	Actual Reserves (18-2)	1870
20.	Actual Reserves (%) (19/2) x 100	17.1

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TABLE 10.6.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
MICHIGAN ELECTRIC COORDINATED SYSTEMS GROUP (REGION 10)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	16910	17344	16968	19303	19900	20375	20564	21039
2. PEAK DEMAND	12200	11283	13065	11908	13688	12263	13912	12387
3. PLANNED RESERVES (1-2)	4710	6061	3903	7395	6212	8112	6652	8652
4. PLANNED RESERVES (%) (3/2)X100	38.6	53.7	29.9	62.1	45.4	66.2	47.8	69.8
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-562	-564	-562	-267	-251	-248	-498	-495
6. TOTAL CAPABILITY (1+5)	16348	16780	16406	19036	19649	20127	20066	20544
7. TOTAL RESERVES (6-2)	4148	5497	3341	7128	5961	7864	6154	8157
8. TOTAL RESERVES (%) (7/2)X100	34.0	48.7	25.6	59.9	43.5	64.1	44.2	65.9
9. SCHEDULED MAINTENANCE	846	937	848	1042	995	1100	1028	1136
10. CAPABILITY AFTER MAINTENANCE	15502	15843	15558	17994	18654	19027	19038	19408
11. RESERVES AFTER MAINTENANCE (10-2)	3302	4560	2493	6086	4966	6764	5126	7021
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	27.1	40.4	19.1	51.1	36.3	55.2	36.8	56.7
13. FULL FORCED OUTAGES	778	659	781	734	915	774	946	799
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	14724	15184	14777	17260	17739	18253	18092	18609
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2524	3901	1712	5352	4051	5990	4180	6222
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	20.7	34.6	13.1	44.9	29.6	48.8	30.0	50.2
17. OTHER UNAVAILABLE CAPABILITY	930	1561	933	1737	1094	1834	1131	1894
18. ACTUAL CAPABILITY (14-17)	13794	13623	13844	15523	16645	16419	16961	16715
19. ACTUAL RESERVES (18-2)	1594	2340	779	3615	2957	4156	3049	4328
20. ACTUAL RESERVES (%) (19/2)X100	13.1	20.7	6.0	30.4	21.6	33.9	21.9	34.9

BASED ON FORM ERA-411

TABLE 16.6.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990
MICHIGAN ELECTRIC COORDINATED SYSTEMS GROUP (REGION 18)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	20564	21039	20714	20449	20079	20449	20079	21169	20730	21185
2. PEAK DEMAND	14275	12864	14742	13234	15357	13653	15751	13928	16137	14237
3. PLANNED RESERVES (1-2)	6289	8175	5972	7215	4722	6796	4328	7241	4593	6948
4. PLANNED RESERVES (%) (3/2)X100	44.1	63.5	40.5	54.5	30.7	49.8	27.5	52.0	28.5	48.8
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-258	-255	-259	-255	-257	59	57	61	58	62
6. TOTAL CAPABILITY (1+5)	20306	20784	20455	20194	19822	20508	20136	21230	20788	21247
7. TOTAL RESERVES (6-2)	6031	7920	5713	6960	4465	6855	4385	7302	4651	7010
8. TOTAL RESERVES (%) (7/2)X100	42.2	61.6	38.8	52.6	29.1	50.2	27.8	52.4	28.8	49.2
9. SCHEDULED MAINTENANCE	1028	1136	1036	1104	1004	1104	1004	1143	1037	1144
10. CAPABILITY AFTER MAINTENANCE	19278	19648	19419	19090	18818	19404	19132	20087	19751	20103
11. RESERVES AFTER MAINTENANCE (10-2)	5003	6784	4677	5856	3461	5751	3381	6159	3614	5866
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	35.0	52.7	31.7	44.2	22.5	42.1	21.5	44.2	22.4	41.2
13. FULL FORCED OUTAGES	946	799	953	777	924	777	924	804	954	805
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	18332	18849	18466	18313	17894	18627	18208	19283	18797	19298
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	4057	5985	3724	5079	2537	4974	2457	5355	2660	5061
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	28.4	46.5	25.3	38.4	16.5	36.4	15.6	38.4	16.5	35.5
17. OTHER UNAVAILABLE CAPABILITY	1131	1894	1139	1840	1104	1840	1104	1905	1140	1907
18. ACTUAL CAPABILITY (14-17)	17201	16955	17327	16473	16790	16787	17104	17378	17657	17391
19. ACTUAL RESERVES (18-2)	2926	4091	2585	3239	1433	3134	1353	3450	1520	3154
20. ACTUAL RESERVES (%) (19/2)X100	20.5	31.8	17.5	24.5	9.3	23.0	8.6	24.8	9.4	22.2

BASED ON FORM ERA-411

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TABLE 10.7.1

INSTALLED NET SUMMER CAPABILITY BY TYPE, AS OF MAY 31 - MW

MICHIGAN ELECTRIC COORDINATED SYSTEMS (REGION 10)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	698	9576	2213	305	172	143	557	54	166	1872	15856
% TOTAL	4.4	60.5	14.6	1.9	1.1	0.9	3.5	0.3	1.0	11.8	100.0
SUMMER 1981	698	9632	2213	305	172	143	557	54	166	1872	15912
% TOTAL	4.4	60.6	14.5	1.9	1.1	0.9	3.5	0.3	1.0	11.8	100.0
SUMMER 1982	698	9632	3311	305	172	143	557	54	166	1872	16910
% TOTAL	4.1	57.0	19.6	1.8	1.0	0.8	3.3	0.3	1.0	11.1	100.0
SUMMER 1983	698	9632	3311	305	172	143	557	60	166	1872	16916
% TOTAL	4.1	56.9	19.6	1.8	1.0	0.8	3.3	0.4	1.0	11.1	100.0
SUMMER 1984	2575	9690	3311	305	172	29	557	60	166	1872	18737
% TOTAL	13.7	51.7	17.7	1.6	0.9	0.2	3.0	0.3	0.9	10.0	100.0
SUMMER 1985	3080	10354	3311	305	172	29	557	60	166	1872	19906
% TOTAL	15.5	52.1	16.6	1.5	0.9	0.1	2.8	0.3	0.8	9.4	100.0
SUMMER 1986	3080	11018	3311	305	172	29	557	60	166	1872	20570
% TOTAL	15.0	53.6	16.1	1.5	0.8	0.1	2.7	0.3	0.8	9.1	100.0
SUMMER 1987	2445	11168	3311	305	172	29	557	60	166	1872	20085
% TOTAL	12.2	55.6	16.5	1.5	0.9	0.1	2.8	0.3	0.8	9.3	100.0
SUMMER 1988	2445	11168	3311	305	172	29	557	60	166	1872	20085
% TOTAL	12.2	55.6	16.5	1.5	0.9	0.1	2.8	0.3	0.8	9.3	100.0
SUMMER 1989	2445	11168	3311	305	172	29	557	60	166	1872	20085
% TOTAL	12.2	55.6	16.5	1.5	0.9	0.1	2.8	0.3	0.8	9.3	100.0
SUMMER 1990	3096	11168	3311	305	172	29	557	60	166	1872	20736
% TOTAL	14.9	53.9	16.0	1.5	0.8	0.1	2.7	0.3	0.8	9.0	100.0

BASED ON FORM ERA-411

TABLE 16.7.2

INSTALLED NET WINTER CAPABILITY BY TYPE OF FUEL, AS OF NOV.30 - MW

MICHIGAN ELECTRIC COORDINATED SYSTEMS (REGION 10)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	803	9617	2323	356	173	143	729	53	167	1872	16276
% TOTAL	4.9	59.1	14.3	2.4	1.1	0.9	4.5	0.3	1.0	11.5	100.0
WINTER 1981	803	9673	2323	356	173	143	729	53	167	1872	16332
% TOTAL	4.9	59.2	14.2	2.4	1.1	0.9	4.5	0.3	1.0	11.5	100.0
WINTER 1982	803	9673	3335	356	173	143	729	53	167	1872	17344
% TOTAL	4.6	55.8	19.2	2.3	1.0	0.8	4.2	0.3	1.0	10.8	100.0
WINTER 1983	803	9731	3335	356	173	143	729	59	167	1872	17408
% TOTAL	4.6	55.8	19.2	2.3	1.0	0.8	4.2	0.3	1.0	10.8	100.0
WINTER 1984	3226	10395	3335	356	173	29	729	59	167	1872	20381
% TOTAL	15.8	51.1	16.4	1.5	0.8	0.1	3.6	0.3	0.8	9.2	100.0
WINTER 1985	3226	11059	3335	356	173	29	729	59	167	1872	21045
% TOTAL	15.3	52.6	15.8	1.5	0.8	0.1	3.5	0.3	0.8	8.9	100.0
WINTER 1986	3226	11059	3335	356	173	29	729	59	167	1872	21045
% TOTAL	15.3	52.6	15.8	1.5	0.8	0.1	3.5	0.3	0.8	8.9	100.0
WINTER 1987	2486	11209	3335	356	173	29	729	59	167	1872	20455
% TOTAL	12.2	54.8	16.3	1.5	0.8	0.1	3.6	0.3	0.8	9.2	100.0
WINTER 1988	2486	11209	3335	356	173	29	729	59	167	1872	20455
% TOTAL	12.2	54.8	16.3	1.5	0.8	0.1	3.6	0.3	0.8	9.2	100.0
WINTER 1989	3226	11209	3335	356	173	29	729	59	167	1872	21195
% TOTAL	15.2	53.0	15.7	1.5	0.8	0.1	3.4	0.3	0.8	8.8	100.0
WINTER 1990	3242	11209	3335	356	173	29	729	59	167	1872	21211
% TOTAL	15.3	52.9	15.7	1.5	0.8	0.1	3.4	0.3	0.8	8.8	100.0

BASED ON FORM ERA-411

SECTION XIV.2
ELECTRIC RELIABILITY COUNCIL OF TEXAS
(ERCOT)

Electric Reliability Council Of Texas (ERCOT)
Electric Region 23

Introduction

The members of the Electric Reliability Council of Texas (ERCOT) supply electric power within the State of Texas only and do not operate in synchronism with any of the other nine Electric Reliability Council areas. The entire ERCOT area is included in the Texas Interconnected Systems Group (TIS) (Electric Region 23). The area is divided into the North and South Texas areas for planning and operating purposes, and each area is monitored by a security center. There are seven control centers in the South Texas area and three in the North Texas area.

ERCOT usually experiences its peak electric load in July or August during periods of prolonged hot dry weather. Its winter peak occurs in December or January and is approximately 75 percent of the summer peak load.

During the year 1980, ERCOT obtained 66.8 percent of its electric generation from natural gas, 32.4 percent from coal and lignite, 0.6 percent from fuel oil, and 0.2 percent from hydro (see Table 2A.1, below).

Table 2A.1

1980 Net Dependable Capability and Generation by Fuel Type

Texas Interconnected Systems Group

Fuel Type	Net Dependable Capability (MW)	Net Dependable Capability (% of Total)	Generation (GWH)	Generation (% of Total)
Coal	9,674	22.7	52,440.0	32.4
Oil	102	0.2	872.0	0.6
Natural Gas	32,567	76.5	108,055.4	66.8
Nuclear	0	0.0	0.0	0.0
Hydro	230	0.6	348.0	0.2
Other	0	0.0	0.0	0.0
Total	42,573	100.0	161,715.4	100.0

The existing high voltage transmission system is at the 345 KV level and extends east to west in the North Texas portion of the area and north to south between the North and South Texas areas. The 345 KV transmission system between North and South Texas was constructed primarily for reliability and until recently was not used for economy energy transactions.

Texas is presently isolated electrically from other Electric Regions in the nation. The Central & South West Corporation (CSW) has petitioned the Federal Energy Regulatory Commission (FERC) to order ERCOT to interconnect with the Southwest Power Pool Reliability Council (SPP). As a result of this petition, systems in ERCOT and SPP have signed an interconnection agreement which has not been approved by FERC. The agreement calls for constructing two direct current ties -- one in East Texas, and one from Oklahoma into West Texas. As reported in the April 1981 ERA-411 Report, the ± 500 KV D.C. line in East Texas is proposed for January 1985 and an A.C. link to the other D.C. tie is planned for January 1984.

The Texas Interconnected Systems (TIS) group has been a high growth area with an annual compound rate of growth of approximately 10 percent for both peak demand and energy during the period 1950 through 1976. During the early years of this period, electric usage increased rapidly. However, the annual growth rate of electric usage has been declining as shown in the following table:

Table 2A.2

Compound Annual Growth Rate
Texas Interconnected Systems Group

Period	Compound Annual Growth Rate Peak Demand (%)	Compound Annual Growth Rate Annual Energy (%)
1950-1960	12.9	11.8
1960-1970	10.1	10.5
1970-1976	6.4	6.3

Figures 2A.1 and 2A.2 show graphically how the 10-year summer and winter demand projections of ERCOT have decreased in the past 10 years. These projections, as reported in the FPC-383 and ERA-411 Reports, held fairly steady around the 9.0 percent-per-year growth rate from 1970 to 1974. After the oil embargo of late 1973 and early 1974, utility demand forecasts began to drop and by 1981, the long range summer load growth is forecasted to be under 5.0 percent.

The data used in this report on load and supply for Region 23 is based on ERCOT's ERA-411 Report of April 1, 1981. Net dependable capability was determined by the Staff using existing capacity (Item 2-A) and adding to it projected capacity (Item 2-B). For the purpose of this report, Staff used a May 31 in-service date as a cutoff date for including scheduled capacity in the planned capability for the summer peak and November 30 for the winter peak. As a result, the planned capability as calculated by Staff is different from that reported by ERCOT in Item 3-A of ERA-411. Table 2A.3 shows the differences in capability between ERCOT's figures shown in Item 3-A of ERA-411 and the figures calculated using Staff's criteria. In some cases, due to ERCOT's projected retirements, Staff capability estimates were higher than ERCOT's.

Table 2A.3

Difference In Peak Period Planned Capabililty
Due to Difference In Cut-off Dates 1/
For Including New Generating Units
Electric Region 23

Year	Summer (MW)	Winter (MW)
1981	19	-26
1982	1,569	-3
1983	19	1019
1984	19	-203
1985	-209	-196
1986	19	392
1987	419	-331
1988	419	1,554
1989	419	1,279
1990	-318	-61

1/ Tabulated difference = (ERA-411 Capacity) - (Capacity Computed by Staff)

[redacted]

Scheduled maintenance, full forced outage, and other unavailable capability are all as estimated by PSR with one exception: The 1981 summer peak period scheduled maintenance is as reported in the ERA-411 Report. All other figures were calculated using a historical percent of net dependable capability as listed in the following table.

Table 2A.4

Historical Percentages for Scheduled Maintenance Full Forced Outage, and Other Unavailable Capability

Electric Region	Scheduled Maintenance		Full Forced Outage		Other Unavailable Capability	
	Summer	Winter	Summer	Winter	Summer	Winter
Texas Interconnected Systems Group (Region 23)	2.1	16.1	3.9	6.5	5.9	9.0

These percentages were calculated using data submitted in FPC Form 12E-2. A historical total for each category was determined for the peak month during the 1977-1980 summers and the 1977-78 through 1979-1980 winters. A percent of net dependable capability was calculated for each peak period for each category and averaged to obtain the figures shown in Table 2A.4.

A review of ERCOT's 1981 ERA-411 Report reveals several deviations from prior reports. The decline in future 10-year load growth projections has already been discussed. Another deviation is the method utilized in the 1981 report regarding future capacity installation. There were seven coal-fired generating units, totalling 4,450 MW, reported as planned for service in the late 1980's in the 1980 ERA-411 filing, which are not shown in the 1981 report. These units were replaced, in part, by six entries totaling 2,900 MW. These six entries have the same footnote, which reads as follows:

> May be obtained by rescheduling of units under construction/planned, load reduction by load management and conservation, deferral of unit retirements, and/or capacity purchases.

This change in reporting future capacity reflects more uncertainty as to the future than has been shown in previous ERA-411 Reports.

Load and Supply

The Texas Interconnected Systems Group (Region 23) had historical 1980 summer and winter actual reserves of 16.0 percent and 28.0 percent, respectively (see Table 2A.6). These reserves reflect the effects of scheduled maintenance, full forced outages and other unavailable capability. Region 23 has had ample reserves in all the 1977-1980 peak periods.

Region 23 experienced a substantial increase in peak demand growth in 1980 as shown in Table 2A.5 below. Summer peak demand, which decreased in 1979, below the 1978 value, increased by 12.6 percent in 1980. Winter peak demand increased by 8.1 percent over 1979 and annual energy requirements increased 7.9 percent.

[redacted]

Table 2A.5

Historical Peak Demand and Energy
Texas Interconnected Systems Group

Year	Demand				Annual Energy Requirements		Annual Load Factor
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWH)	Growth (%)	(%)
1977	26,894	-	20,203	-	136,743	-	58.0
1978	28,645	6.5	21,521	6.5	147,608	8.0	58.8
1979	28,455	-0.7	22,052	2.5	150,231	1.8	60.3
1980	32,032	12.6	23,849	8.1	162,152	7.9	57.8

Natural gas is still the primary fuel source, but the use of coal in Region 23 is increasing. In 1980, 66.8 percent of the Region's total generation was supplied by gas, while 32.4 percent was supplied by coal (see Table 2A.1).

[NOTE: See Appendix C for a detailed analysis of the 1981 summer peak period for Region 23.]

The 1981-82 winter peak period is given in Table 2A.7. The winter actual reserves appear adequate (18.0 percent) even though there are projected unit outages totalling 13,592 MW or 31.6 percent of total capability.

The only new generating capacity projected for service in 1981 is the 545 MW Sandow No. 4 lignite-fired unit of Texas Power and Light Company.

The 1981 noncoincident summer peak demand for Region 23 is projected by ERCOT to be 32,825 MW which is an increase of approximately 2.5 percent over the actual noncoincident 1980 peak. The increase from 1979 to 1980 was 12.6 percent. The large actual load growth of 12.6 percent should be considered in the context of two consecutive summers of abnormal weather conditions: 1979 was below average and 1980 was extremely hot and dry. The estimated peak demand of 32,825 MW is based on average weather conditions. The predicted actual reserve for the 1981 summer peak period is 5,677 MW or 17.3 percent of peak demand (see Appendix C). If Region 23 experienced a load growth in 1981 approaching the 1979-1980 growth, actual reserves could drop to 2,107 MW or 5.8 percent. Even if this occurred, Region 23 should have no difficulties during the 1981 peak period.

Future Perspective

The Texas Interconnected Systems Group (Region 23) is projecting 9,057 MW of additional coal-fired capacity in the 1982-1990 study period (see Table 2A.8). Coal, which constituted 22.7 percent of total capability in December 1980, will increase to 32.4 percent in December 1990. Nuclear capacity will be installed for the first time in 1982 and by 1990 will total 5,930 MW (see Table 2A.9) or 10.0 percent of total capability. Gas-fired capacity will show a reduction of 2,666 MW by 1990. This is a substantial decrease in the 10-year period (see Table 2A.10) from 76.5 percent in 1980 to 50.0 percent in 1990.

Tables 2A.11 and 2A.12 show predicted total reserves during the 1982-1990 period ranging from 18.3 percent to 27.1 percent during the summer peak. These figures include planned capability, and the net of imports and exports of power. Scheduled maintenance, full forced outage, and other unavailable capability were estimated by PSR using historical figures as discussed in the introduction (see Table 2A.4). These outages result in actual summer reserves ranging from 5.7 percent to 12.2 percent. PSR has estimated that if the W. A. Parish Unit No. 8 (540 MW), scheduled to be in service by the 1983 summer peak, should be delayed until the 1983-84 winter peak, the delay would result in an actual reserve of 10.2 percent in the summer of 1983.

[redacted]

Summer peak demand is projected to grow at an average compound rate of 4.6 percent per year from 1982 to 1990. This is a decrease from 5.2 percent in the previous ERA-411 Report. Winter peak demand and energy requirements are expected to grow at 4.8 percent and 4.7 percent, per year, respectively.

The TIS Group, pending approval from FERC, is planning two direct current (± 500-KV) interconnections with neighboring electric regions. The D.C. tie with Southwestern Electric Power Company (Region 22) is scheduled for January 1985. TIS is planning additional intra-regional transmission lines at 345-KV during the study period for a total of 2,619 miles.

Region 23 appears to have adequate reserve throughout the 1982-1990 study period based on the 1981 ERA-411 load growth projection. The historical full-forced outage rate has been 3.9 percent 1/ which was based mainly upon actual forced outages of gas-fired units. The coal-fired and nuclear units projected are of larger size than the existing mature gas-fired units. Generally, new large units exhibit higher forced outage rates for several years. This could increase the capacity outage rate, and actual reserves would then be lower than predicted.

1/ See Table 2A.4

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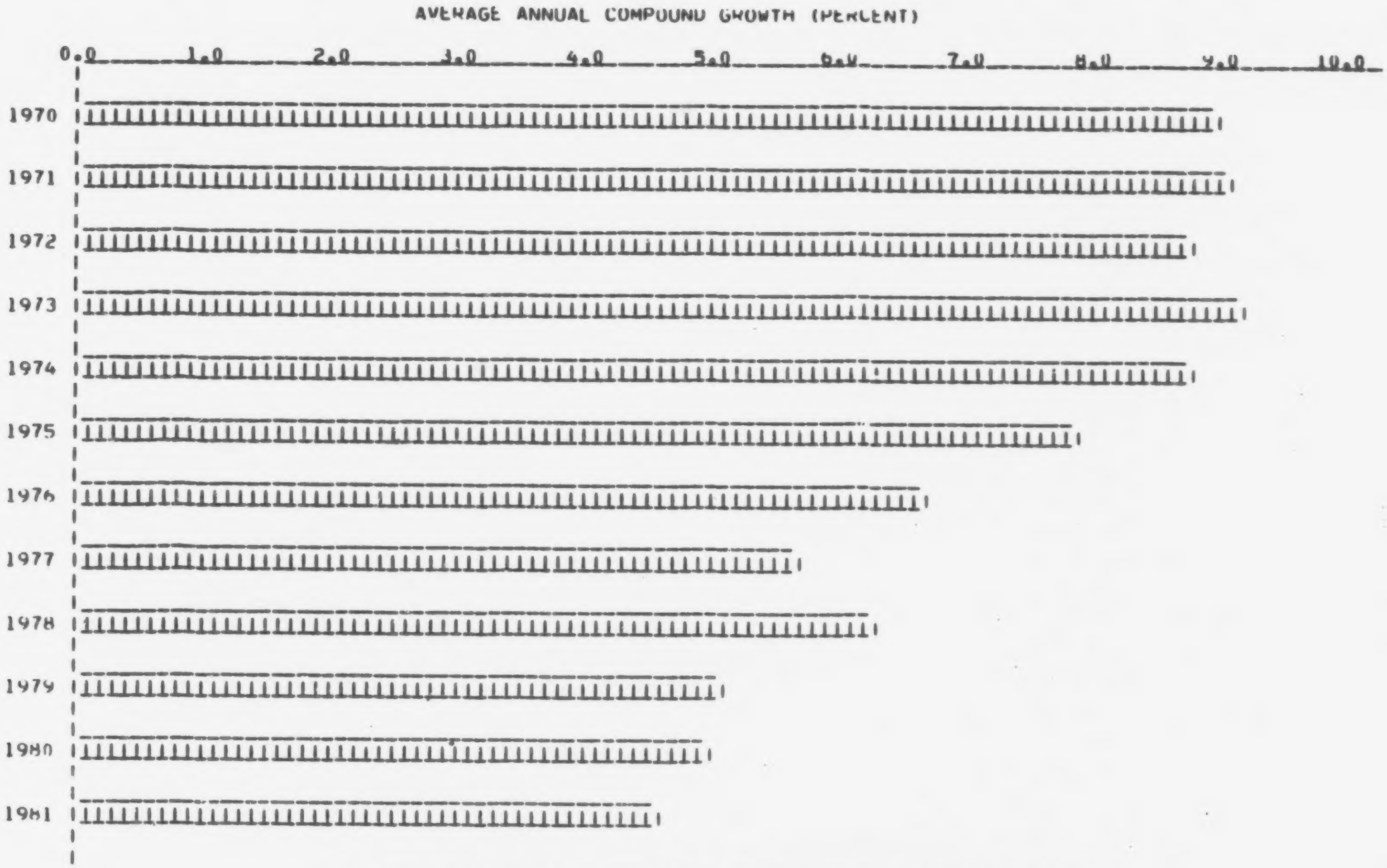
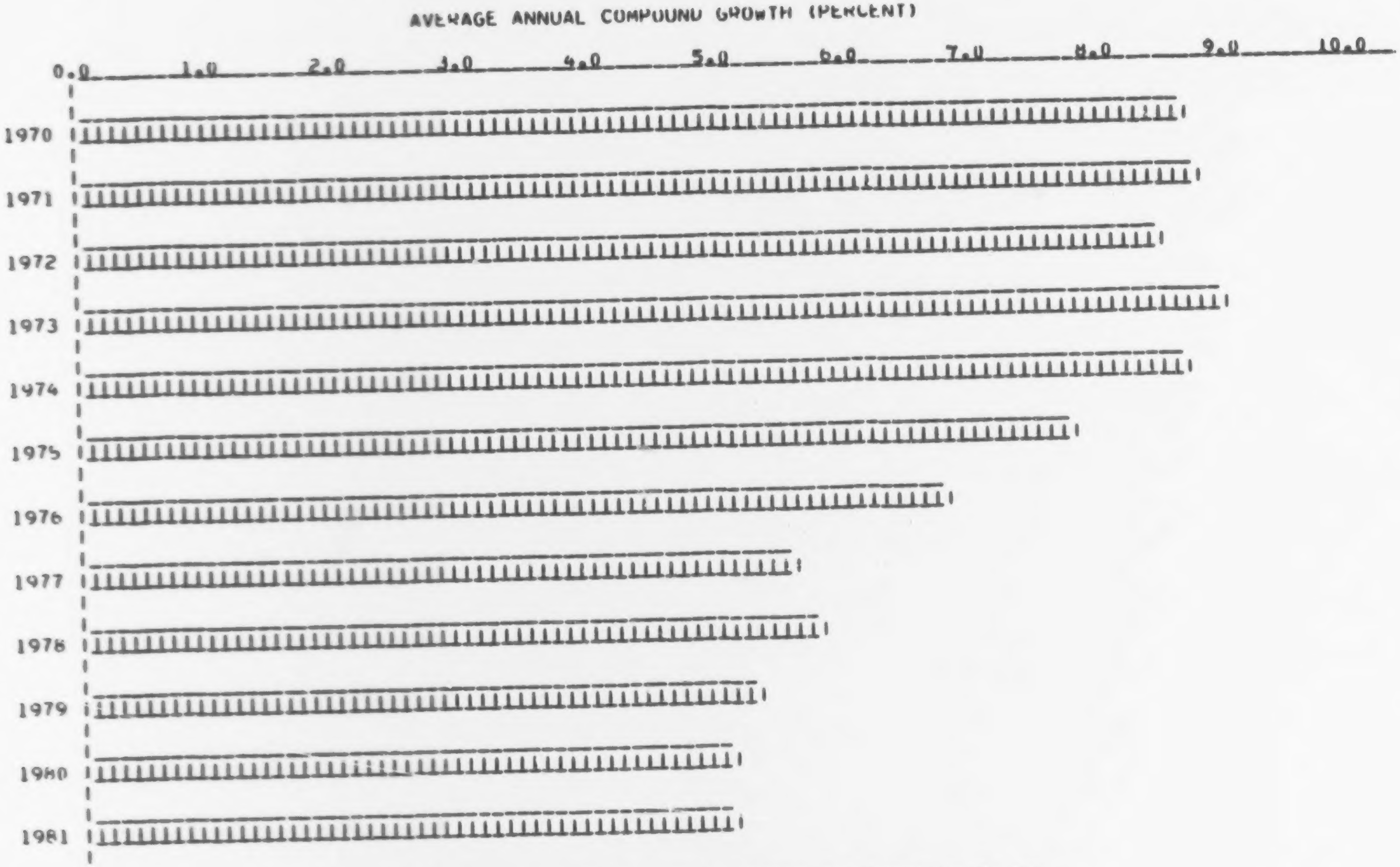


TEN YEAR ESTIMATES OF SUMMER PEAK DEMAND AS REPORTED BY THE
ELECTRIC RELIABILITY COUNCIL OF TEXAS
IN ITS FPC-383 AND ERA-411 ANNUAL REPORTS

Figure 2A.1



TEN YEAR ESTIMATES OF WINTER PEAK DEMAND AS REPORTED BY THE ELECTRIC RELIABILITY COUNCIL OF TEXAS IN ITS FPC-383 AND ERA-411 ANNUAL REPORTS

Figure 2A.2

Table 2A.6

Historical Capability (MW) and Reserves (MW and Percent)
Texas Interconnected Systems Group (Region 23)

	Summer				Winter			
	1977	1978	1979	1980	1977/78	1978/79	1979/80	1980/81
1. Planned Capability	35,565	37,649	40,847	42,172	36,833	39,479	40,777	42,390
2. Peak Demand	26,894	28,645	28,455	32,032	20,203	21,521	22,052	23,849
3. Planned Reserves (1-2)	8,671	9,004	12,392	10,140	16,630	17,958	18,725	18,541
4. Planned Reserves (%) (3/2) x 100	32.2	31.4	43.5	31.7	82.3	83.4	84.9	77.7
5. Net Transactions (Imports-Exports)	-24	35	236	104	189	297	164	135
6. Total Capability (1+5)	35,541	37,684	41,083	42,276	37,022	39,776	40,941	42,525
7. Total Reserves (6-2)	8,647	9,039	12,628	10,244	16,819	18,255	18,889	18,676
8. Total Reserves (%) (7/2) x 100	32.2	31.6	44.4	32.0	83.3	84.8	85.7	78.3
9. Scheduled Maintenance	224	797	1,201	1,053	6,459	5,871	6,509	6,390
10. Capability after Maintenace (6-9)	35,317	36,887	39,882	41,223	30,563	33,905	34.432	36,135
11. Reserves after Maintenance (10-2)	8,423	8,242	11,427	9,191	10,360	12,384	12,380	12,286
12. Reserves after Maintenance (11/2) x 100	31.3	28.8	40.2	28.7	51.3	57.5	56.1	51.5
13. Full Forced Outages	1,821	2,024	961	1,187	2,376	2,950	2,240	3,223
14. Capability after Full Forced Outages (10-13)	33,496	34,863	38,921	40,036	20,187	30,955	32,192	32,912
15. Reserves after Full Forced Outages (14-2)	6,602	6,218	10,466	8,004	7,984	9,434	10,140	9,063
16. Reserves (%) after Full Forced Outages (15/2) x 100	24.5	21.7	36.8	25.0	39.5	43.8	46.0	38.0
17. Other Unavailable Capability	2,406	2,010	1,894	2,871	3,088	4,039	3,411	2,382
18. Actual Capability (14-17)	31,090	32,853	37,027	37,165	25,099	26,916	28,781	30,530
19. Actual Reserves (18-2)	4,196	4,208	8,572	5,133	4,896	5,395	6,729	6,681
20. Actual Reserves (%) (19/2) x 100	15.6	14.7	30.1	16.0	24.2	25.1	30.5	28.0

Source: FPC Form 12E-2 and ERA-119M

Table 2A.7

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
TEXAS INTERCONNECTED SYSTEMS GROUP (REGION 23)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	43012	43012
2. PEAK DEMAND	32825	25065
3. PLANNED RESERVES (1-2)	10187	17947
4. PLANNED RESERVES (%) (3/2)X100	31.0	71.6
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	150	150
6. TOTAL CAPABILITY (1+5)	43162	43162
7. TOTAL RESERVES (6-2)	10337	18097
8. TOTAL RESERVES (%) (7/2)X100	31.5	72.2
9. SCHEDULED MAINTENANCE 1/	445	6925
10. CAPABILITY AFTER MAINTENANCE (6-9)	42717	36237
11. RESERVES AFTER MAINTENANCE (10-2)	9892	11172
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	30.1	44.6
13. FULL FORCED OUTAGES 1/	1677	2796
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	41040	33441
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	8215	8376
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	25.0	33.4
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	2538	3871
18. ACTUAL CAPABILITY (14-17)	38502	29570
19. ACTUAL RESERVES (18-2)	5677	4505
20. ACTUAL RESERVES (%) (19/2)X100	17.3	18.0

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Table 2A.8

Projected Coal-fired Generating Units for the Period 1981-1990
As Reported April 1, 1981, to the Department of Energy
Texas Interconnected Systems Group

(Electric Region 23)

	Capability	As Reported April 1		
Unit Name	(MW)	1981	1980	Company
Sandow No. 4	545	3-81	1-81	Texas Power & Light Co.
Gibbons Creek No. 1	400	6-82	6-82	Texas Municipal Power Pool
W.A. Parrish No. 8	540	5-83	5-83	Houston Lighting & Power Co.
Limestone No. 1	700	4-85	4-85	Houston Lighting & Power Co.
Twin Oak No. 1	750 1/	2-86	2-85	Texas Power & Light Co.
Limestone No. 2	700	4-86	4-86	Houston Light & Power Co.
Oklaunion No. 1	640 2/	12-86	1-87	West Texas Utilities Co.
Undetermined	600	3-87	3-87	Houston Lighting & Power Co.
Gibbons Creek No. 2	400	7-87	-	Texas Municipal Power Pool
Twin Oak No. 2	750 1/	2-88	2-86	Texas Power & Light Co.
Undetermined	600	3-88	3-88	Houston Lighting & Power Co.
F.P.P. No 3	400	6-88	6-87	Lower Colorado River Authority
Forest Grove No. 1	750 3/	1-89	1-87	Texas Utilities Co.
Undesignated	400	6-89	6-88	Texas Municipal Power Pool
Martin Lake No. 4	750 3/	1-90	2-85	Texas Utilities Co.
Undetermined	750 3/	1-90	1-88	Texas Utilities Co.
Undesignated	500	4-90	4-89	San Antonio Public Service Bd.
Total	10,174 4/			

1/ Joint ownership: Texas Power & Light Co. (562 MW) and an industrial customer (188 MW).

2/ Joint ownership: West Texas Utilities Co. (328 MW), Central Power & Light Co. (115 MW), Public Service Company of Oklahoma (147 MW) (Region 22), and Southwestern Electric Power Co. (50 MW) (Region 22).

3/ Joint ownership: Texas Power & Light Co., Texas Electric Service Co., and Dallas Power & Light Co.

4/ Of this total, 9,602 MW will be owned by electric utilities in ERCOT, 376 MW will be used by industrial customers in ERCOT, and 197 MW will be owned by electric utilities in Region 22 (Oklahoma Group).

[redacted]

Table 2A.9

Projected Nuclear Generating Units for the Period 1981-1990
As Reported April 1, 1981, to the Department of Energy
Texas Interconnected Systems Group

(Electric Region 23)

Unit Name	Capability (MW)	As Reported April 1		Company
		1981	1980	
Comanche Peak No. 1	1150 1/	6-82	8-81	Texas Utilities Co. Systems
S. Texas Project No. 1	1250 2/	2-84	2-84	Houston Lighting & Power Co.
Comanche Peak No. 2	1150 1/	3-84	1-83	Texas Utilities Co. Systems
S. Texas Project No. 2	1250 2/	2-86	2-86	Houston Lighting & Power Co.
Allens Creek No. 1	1130	12-88	11-87	Houston Lighting & Power Co.

1/ Joint ownership: Texas Utilities Company Systems (90 percent) and Texas Municipal Power Pool (10 percent).

2/ Joint ownership: Houston Lighting & Power Co. (30.8 percent), San Antonio Public Service Board (28 percent), Central Power & Light Co. (24.2 percent), City of Austin (16 percent) and City of Brownsville (1 percent).

Table 2A.10

Summer and Winter Capability by Fuel Type
(Megawatts)
1981-1990

Texas Interconnected Systems Group
(Region 23)

Fuel Type	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Coal	10,221	10,221	10,221	10,621	11,161	11,161	11,161	11,161	11,861	11,861
Oil	102	102	102	102	102	102	102	102	96	96
Gas	32,459	32,459	32,414	32,414	32,422	32,319	32,169	32,054	31,838	31,465
Nuclear	0	0	0	1,150	1,150	1,150	3,550	3,550	3,550	3,550
Hydro	230	230	230	230	230	230	230	230	230	230
Other	0	0	0	0	0	0	0	0	0	0
TOTAL	43,012	43,012	42,967	44,517	45,065	44,962	47,212	47,097	47,575	47,202

Fuel Type	1986		1987		1988		1989		1990	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Coal	13,123	13,123	14,166	14,566	15,729	16,129	16,879	17,279	19,279	19,279
Oil	96	96	96	96	96	96	96	96	96	96
Gas	31,250	31,163	31,093	30,978	30,628	30,503	30,158	30,033	29,793	29,793
Nuclear	4,800	4,800	4,800	4,800	4,800	4,800	5,930	5,930	5,930	5,930
Hydro	230	230	230	230	230	230	230	230	230	230
Other	0	0	1,100	1,100	2,000	2,000	3,200	3,200	4,200	4,200
TOTAL	49,499	49,412	51,485	51,770	53,483	53,758	56,493	56,768	59,528	59,528

Table 2A.11

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
TEXAS INTERCONNECTED SYSTEMS GROUP (REGION 23)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	42967	44517	45065	44962	47212	47097	47575	47202
2. PEAK DEMAND	34557	26153	36070	27340	37576	28759	39547	30104
3. PLANNED RESERVES (1-2)	8410	18364	8995	17622	9636	18338	8028	17098
4. PLANNED RESERVES (%) (3/2)X100	24.3	70.2	24.9	64.5	25.6	63.8	20.3	56.8
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	540	540	570	570	565	565	627	677
6. TOTAL CAPABILITY (1+5)	43507	45057	45635	45532	47777	47662	48202	47879
7. TOTAL RESERVES (6-2)	8950	18904	9565	18192	10201	18903	8655	17775
8. TOTAL RESERVES (%) (7/2)X100	25.9	72.3	25.5	66.5	27.1	65.7	21.9	59.0
9. SCHEDULED MAINTENANCE 1/	902	7167	946	7239	991	7583	999	7600
10. CAPABILITY AFTER MAINTENANCE (6-9)	42605	37890	44689	38293	46786	40079	47203	40279
11. RESERVES AFTER MAINTENANCE (10-2)	8048	11737	8619	10953	9210	11320	7656	10175
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	23.3	44.9	23.9	40.1	24.5	39.4	19.4	33.8
13. FULL FORCED OUTAGES 1/	1676	2894	1758	2923	1841	3061	1855	3068
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	40929	34996	42931	35370	44945	37018	45348	37211
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	6372	8843	6861	8030	7369	8259	5801	7107
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	18.4	33.8	19.0	29.4	19.6	28.7	14.7	23.6
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	2535	4007	2659	4047	2786	4239	2807	4248
18. ACTUAL CAPABILITY (14-17)	38394	30989	40272	31323	42159	32779	42541	32963
19. ACTUAL RESERVES (18-2)	3837	4836	4202	3983	4583	4020	2994	2859
20. ACTUAL RESERVES (%) (19/2)X100	11.1	18.5	11.6	14.6	12.2	14.0	7.6	9.5

COAL UNIT DELAYS ASSUMED POSSIBLE BY ERA

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. POSSIBLE COAL DELAYS	0	0	540	0	0	0	0	0
22. ACTUAL CAPABILITY WITH COAL DELAYS (18-21)	38394	30989	39732	31323	42159	32779	42541	32963
23. ACTUAL RESERVES WITH COAL DELAYS (22-2)	3837	4836	3662	3983	4583	4020	2994	2859
24. ACTUAL RESERVES (%) WITH COAL DELAYS (23/2)X100	11.1	18.5	10.2	14.6	12.2	14.0	7.6	9.5

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Table 2A.12

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990

TEXAS INTERCONNECTED SYSTEMS GROUP (REGION 23)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	49499	49412	51485	51770	53483	53758	56493	56768	59528	59528
2. PEAK DEMAND	41337	31719	43281	33289	45211	34816	47207	36409	49058	38233
3. PLANNED RESERVES (1-2)	8162	17693	8204	18481	8272	18942	9286	20359	10470	21295
4. PLANNED RESERVES (%) (3/2)X100	19.7	55.8	19.0	55.5	18.3	54.4	19.7	55.9	21.3	55.7
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	632	632	605	655	655	655	771	771	906	906
6. TOTAL CAPABILITY (1+5)	50131	50044	52090	52425	54138	54413	57264	57539	60434	60434
7. TOTAL RESERVES (6-2)	8794	18325	8809	19136	8927	19597	10057	21130	11376	22201
8. TOTAL RESERVES (%) (7/2)X100	21.3	57.8	20.4	57.5	19.7	56.3	21.3	58.0	23.2	58.1
9. SCHEDULED MAINTENANCE 1/	1039	7955	1081	8335	1123	8655	1186	9140	1250	9584
10. CAPABILITY AFTER MAINTENANCE (6-9)	49092	42089	51009	44090	53015	45758	56078	48399	59184	50850
11. RESERVES AFTER MAINTENANCE (10-2)	7755	10370	7728	10801	7804	10942	8871	11990	10126	12617
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	18.8	32.7	17.9	32.4	17.3	31.4	18.8	32.9	20.6	33.0
13. FULL FORCED OUTAGES 1/	1930	3212	2008	3365	2086	3494	2203	3690	2322	3859
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	47162	38877	49001	40725	50929	42264	53875	44709	56862	46981
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	5825	7158	5720	7436	5718	7448	6668	8300	7804	8748
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	14.1	22.6	13.2	22.3	12.6	21.4	14.1	22.8	15.9	22.9
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	2920	4447	3038	4659	3155	4838	3333	5109	3512	5358
18. ACTUAL CAPABILITY (14-17)	44242	34430	45963	36066	47774	37426	50542	39600	53350	41623
19. ACTUAL RESERVES (18-2)	2905	2711	2682	2777	2563	2610	3335	3191	4292	3390
20. ACTUAL RESERVES (%) (19/2)X100	7.0	8.5	6.2	8.3	5.7	7.5	7.1	8.8	8.7	8.9

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM 12E-2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

SECTION XIV.3
MID-ATLANTIC AREA COUNCIL
(MAAC)

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Pennsylvania-New Jersey-Maryland Interconnection Region (PJM)

Electric Region 5

Historical Perspective

The Mid-Atlantic Area Council (MAAC) is comprised of the Pennsylvania-New Jersey-Maryland Interconnection (PJM), municipal systems and electric cooperatives. Under the PJM power pooling agreement, eleven investor-owned (privately-owned) electric utilities operate in many respects as a single system. MAAC acts as a forum for coordination of the bulk power supply planning and operating activities of PJM and the MAAC associate members (the municipal and cooperative systems). The MAAC region includes all of Delaware and the District of Columbia, major portions of Pennsylvania (75%), New Jersey (97%) and Maryland (60%), and a small portion of Virginia. PJM operations are coordinated from a single operating center with each PJM member company's resources and loads committed as a single operating entity.

The geographic location of this region is such that it is the bridge between the coal-burning utilities of the West and the imported oil-dependent utilities of the Northeast. However, transmission bottlenecks limit the east-west transfers of economy energy. MAAC has somewhat more base load coal than base load oil generating capability. Fuel oil for this region is primarily imported from the Middle East. Table 3A.1 shows percentages of generation by fuel type for the years 1977 through 1980 and capability by fuel type for 1979 and 1980.

TABLE 3A.1

ACTUAL 1977-1980 GENERATION BY FUEL TYPE

AND ACTUAL 1979-1980 CAPABILITY BY FUEL TYPE

PENNSYLVANIA NEW JERSEY MARYLAND INTERCONNECTION REGION

PJM GENERATION
PERCENTAGE OF TOTAL

YEAR	NUCLEAR	HYDRO	COAL	OIL	GAS
1977	20	2	49	29	(*)
1978	22	2	46	30	0
1979	20	2	55	21	2
1980	18	1	59	17	5

PLANT CAPABILITY
PERCENTAGE OF TOTAL

YEAR	NUCLEAR	HYDRO	COAL	OIL	GAS
1979	16	5	32	46	1
1980	16	5	35	42	2

(*) LESS THAN 1%

BASED ON FORM ERA-411 AND FPC FORM 4

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Slow growth in peak demand and increased oil conservation efforts have increased the need for base load coal-fired generation and decreased the need for oil and gas. The drop in nuclear generation experienced in 1979 and 1980 is a direct result of the Three Mile Island accident.

Historical values and growth rates for net energy requirements, summer and winter peak demands, and annual load factors, as obtained from ERA-411 and FPC 12E-2 reports, are shown in Table 3A.2.

TABLE 3A.2

ACTUAL ANNUAL NET ENERGY, PEAK DEMANDS, AND LOAD FACTORS

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

	NET ENERGY		SUMMER PEAK		WINTER PEAK		
YEAR	G W H	PERCENT CHANGE	M W	PERCENT CHANGE	M W	PERCENT CHANGE	LOAD FACTOR
1977	163,377		32,180		27,967		58
1978	169,006	3.5	31,686	(2.0)	28,529	2.0	61
1979	171,810	1.6	31,654	(0.1)	27,967	(2.0)	62
1980	175,622	2.3	34,525	9.1	29,730	6.3	58
GROWTH 1977-80		2.5		2.4		2.1	

The average annual net energy growth rate over the 4 year historical period was 2.5%, and annual summer peak demand growth was 2.4%. The unusually high demand growth experienced during the 1979-1980 period was a result of extreme weather conditions, that is, a relatively cool 1979 summer compared to a very hot 1980 summer. These weather conditions also affected energy growth, though to a lesser degree, which resulted in a lower load factor. Table 3A.3 shows the actual 1979/1980 winter generating capability by prime mover and fuel type.

[redacted]

Table 3A.3
PJM Capability by Prime Mover and Fuel Type - 1979/80*

Capacity Type	Fuel Type	Winter 1979/80 Capability MW	Winter 1979/80 Capability %
Steam	Nuclear	7,226	15.2
Steam	Coal	15,106	31.9
Steam	Oil	12,971	27.3
Steam	Gas	0	0
Hydro	-	952	2.0
Pumped Storage	-	1,286	2.7
Gas Turbine & Diesel	Oil	9,090	19.2
Gas Turbine	Gas	294	0.6
Combined Cycle	Oil	530	1.1
Combined Cycle	Gas	0	0
Other		0	0
Total		47,455	100.0

To meet the 1979 generation requirements, fuel consumption was:

34.3 million tons of coal;
4.3 million barrels of distillate oil;
64.7 million barrels of residual oil;
76.8 million mcf of natural gas.

*From NERC 1980 Summary of Projected Peak Demand, Generating Capability and Fossil Fuel Requirements.

Since the Federal Energy Regulatory Commission (FERC) gave only a temporary exemption from the prohibition of gas use by the utilities, future use of this fuel for electric generating purposes remains in doubt. There are at present nine nuclear units in the region and six more are under construction. There had been seven nuclear units planned but the Jersey Central Power and Light Company's Unit Number 1 at Forked River, scheduled for service in 1986, has been cancelled. The future of Three Mile Island No. 2 remains in doubt at this time. Three Mile Island Unit No. 1 was not damaged in the accident to Three Mile Island No. 2, but projected NRC hearings indicate that this unit will be kept out of service for most or all of 1981.

Table 3A.4 shows the summer and winter load, capability, and reserves for the period 1977 through 1980. The PJM system had adequate reserves to meet the load during the 1977-1980 peak periods, with planned reserves varying between 30% and 41% for the summer periods and between 51% and 59% in the winter periods. After consideration of net sales and purchases and capacity out of service, the planned reserves were reduced to actual reserves of 7% to 20% for summer and 7% to 32% for winter. The planned reserve criteria, as dictated by the PJM Agreement, approximates 22% - Table 3A.5 shows planned, available and actual reserves during summer and winter peak periods for the 4-year historical period.

[redacted]

TABLE 3A.5

RESERVE MARGINS IN PERCENT

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

YEAR	PLANNED RESERVES	AVAILABLE RESERVES	ACTUAL RESERVES
SUMMER			
1977	37.0	27.2	8.8
1978	38.1	25.7	19.7
1979	40.9	34.6	14.0
1980	29.6	11.6	6.9
WINTER			
1977	58.1	43.9	19.6
1978	56.5	38.9	25.8
1979	59.1	36.2	6.6
1980	51.0	26.5	32.4

BASED ON FORM FPC 12E-2

The reserve policy for MAAC, as reported in the ERA-411 report, states that the, "Operating Reserve is generating capability and equivalent generation in excess of forecast system peak load which is available within 30 minutes or less to provide primarily for adequate tie line regulation in the event of load variations or equipment failure and, under certain conditions, area protection. The Operating Reserve is divided into Primary and Secondary Reserves.

1. Primary Reserve is that amount of generation capability or equivalent generation in excess of system load which is synchronized to the system or on standby and ready for immediate startup, and which is capable of being loaded within 10 minutes or less to provide for adequate tie line regulation in the event of load variations or equipment failure. The Primary Reserve is subdivided into Spinning Reserve and Quick-Start Reserve.

   a. Spinning Reserve is that portion of Primary Reserve synchronized to the system.

   b. Quick-Start Reserve is any remaining portion of Primary Reserve, adjusted by a factor to allow for the probability of failure of equipment to start. The pumping load of pumped storage hydro plants, when counted as Primary Reserve, is considered to fall within this category.

2. Secondary Reserve is that generating capability or equivalent generation in excess of system load which is either synchronized to the system or on standby and ready to startup, and which is capable of being loaded within from 10 to 30 minutes of the occurrence of a contingency."

[redacted]

In addition, there are load reduction programs to meet emergencies in the event of insufficient operating reserve. Table 3A.6 lists the reduction procedures and the estimated load reductions.

TABLE 3A.6

EMERGENCY CURTAILMENT PROCEDURES

PENNSYLVANIA - NEW JERSEY - MARYLAND INTERCONNECTION REGION

EMERGENCY PROCEDURE	ESTIMATED PEAK LOAD REDUCTION
1. CURTAILMENT OF NON-ESSENTIAL UTILITY SYSTEM LOAD.	100 MW
2. INTERRUPTION OF INTERRUPTIBLE CONTRACT SYSTEM LOAD.	0
3. VOLTAGE REDUCTION OF 3 PERCENT.	425 MW
VOLTAGE REDUCTION OF 5 PERCENT.	500 MW
4. OPERATION OF AUTOMATIC UNDERFREQUENCY RELAYS:	
AT 59.3 HZ	3,700 MW
AT 58.9 HZ	7,800 MW
AT 58.5 HZ	11,900 MW
5. OTHER LOAD PRESERVATION PROCEDURES:	
VOLUNTARY CUSTOMER LOAD CURTAILMENT.	1,400 MW
RADIO AND TELEVISION LOAD CURTAILMENT APPEAL.	VARIABLE
MANUAL LOAD DUMPING.	10,000 MW

BASED ON FORM ERA-411

According to the information provided in the MAAC ERA-411 report, "The need for load reduction procedures is assessed for the interconnection as a whole by the PJM Interconnection Dispatcher, who then notifies the PJM member systems of the total requirement and their share. In the absence of constraining local conditions, each member system initiates the specified procedure to reduce load in an amount equal to its prearranged share of the Interconnection requirement.

In addition to these manual procedures, underfrequency relays are installed to shed load automatically in the event of a power shortage which has caused system frequency to decay. Approximately 30% of the Interconnection load can be shed in this manner:

Frequency	Minimum Load Dumped
59.3 Hz	10%
58.9 Hz	10%
58.5 Hz	10%

[redacted]

The underfrequency relays are sufficiently distributed throughout PJM so that if any major area becomes isolated with generation deficiency and experiences declining frequency, 10% of that area's load will automatically be shed at each frequency listed above."

The PJM companies also have interruptible load contracts with fourteen customers. The total connected load that can be interrupted is 257 MW from industrial accounts with a normal aggregate load of 250 MW. Table 3A.7 shows the additional detail.

TABLE 3A.7

INTERRUPTIBLE LOAD CONTRACTS

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

UTILITY	INTERRUPTIBLE LOAD - MW	CONTRACTUAL CONDITIONS
PSEG	130	LOAD REDUCTION UPON 2 HOUR NOTICE.
GPU	34	LOAD REDUCTION UPON 30 MINUTE NOTICE. NUMBER OF CURTAILMENTS NOT TO EXCEED 20, NOR EXCEED 150 HOURS PER YEAR.
BAGE	3	LOAD REDUCTION UPON 2 HOUR NOTICE CURTAILMENT OF MAXIMUM MEASURED DEMAND BY AT LEAST 2 MW.
DEPL	90	LOAD REDUCTION UPON 30 MINUTE NOTICE. LIMITED TO RATE "Q" CUSTOMERS CONTRACT FOR FIRM AND CONTROLLABLE DEMANDS - MINIMUM 2,000 KW TOTAL. LOAD REDUCTION MADE ONLY BETWEEN 8AM-9PM EST OR 9AM-10PM EDST AND ONLY TO AVOID NEW COMPANY PEAK. (3 CUSTOMERS)

BASED ON FORM ERA-411

Note: PSEG - Public Service Electric & Gas Co.

GPU - General Public Utilities:Jersey Central Power & Light Co.; Metropolitan Edison Co.; Pennsylvania Electric Co.

BAGE - Baltimore Gas & Electric Co.

DEPL - Delmarva Power & Light Co.

[redacted]

PJM is geographically situated in a suitable location for wheeling energy for the purpose of fuel conservation. This was demonstrated when, during the 1977-78 coal strike, oil-fueled generation was moved from East to West (from the oil-fired plants of New England and New York to the coal dependent utilities of the West). More recently, the reverse occurred in the coal-by-wire oil conservation transfers of energy West to East. The transmission is basically strong in both the East and West portions of the system. As of December 31, 1980 there were approximately 1,263 circuit miles of 500 KV lines, 160 circuit miles of 345 KV lines, and 4,400 circuit miles of 230 KV lines. Included are 53 inter-system connection points and 27 interpool connection points with New York Power Pool, Cleveland Electric Illuminating Co., Allegheny Power System and Virginia Electric & Power Company. In early 1981 the Hosensack-Elroy 500 KV line was placed in service, materially improving PJM's ability to accommodate East-West intra-regional energy transfers.

Current Perspective

MAAC is traditionally a summer peaking area. The 1981 summer peak forecast is about 14.1% higher than the 1980-81 winter peak. Total net energy for 1981 is expected to be 175,930 Gwh which is 0.2% above 1980 - a somewhat smaller increase than experienced in the previous year. The annual load factor on the summer peak would then be 59.8%, as indicated on Table 3A.8. Appendix C contains a detailed discussion of the MAAC 1981 summer situation.

The winter peak is expected to be 30,112 MW, an increase of 1.3% over 1980. The 1981 planned winter capability is 48,771 MW. Table 3A.9 shows the demands, resources and reserves for the 1981 summer and winter peaks. (The methodology used to derive actual reserves for the period 1981-1990, shown on Table 3A.9 and elsewhere in this section, is described in Appendix C.)

The planned capability shown on Table 3A.9 includes 1,114 MW of new capacity - the Salem No. 2 nuclear unit is included as being available for the summer season and retirements of 40 MW. The peak demands shown on Table 3A.9 and Tables 3A.10.1, 3A.10.2 and 3A.10.3 include interruptible load and, therefore, differ from the peak demand projections as reported in the ERA-411.

There are approximately 133 miles of 500 KV line and approximately 180 miles of 230 KV transmission lines scheduled for installation during 1981. These lines are primarily for local area protection and increased load-carrying capacity.

The Three Mile Island Plant outage (which is considered a forced outage for the purpose of this report) is creating a voltage problem in central Pennsylvania. However, with the Salem #2 Nuclear Plant on line, this problem should be materially alleviated.

Future Perspective

Forecasts for the 1981-1990 time frame include an average summer peak demand growth of 2.3% per year. However, for the first five years of the period, the anticipated peak demand growth is projected at 2.6%. During the 1981-1990 period, annual energy requirements are expected to grow by approximately 3.0%. Detailed tables of projected capability growth and reserves are included in Tables 3A.10.1, 3A.10.2 and 3A.10.3. Table 3A.8 outlines the projected energy and peak demand growth during this period.

[redacted]

TABLE 3A.8

PROJECTED ENERGY AND PEAK DEMAND

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

YEAR		ENERGY REQUIREMENTS		SUMMER PEAK DEMAND		WINTER PEAK DEMAND		ANNUAL LOAD FACTOR
		GWH	PERCENT GROWTH	MW	PERCENT GROWTH	MW	PERCENT GROWTH	PERCENT
1981		175,930	0.2	34,102	(1.2)	30,112	1.3	59.8
1982		182,822	3.9	35,162	3.1	31,182	3.6	60.2
1983		188,702	3.2	36,032	2.5	32,222	3.4	60.6
1984		194,706	3.2	36,972	2.6	33,242	3.2	60.8
1985		200,502	3.0	37,792	2.2	34,212	2.9	61.4
GROWTH	81-85		3.3		2.6		3.4	
1986		206,241	2.9	38,692	2.4	35,162	2.8	61.7
1987		211,922	2.8	39,512	2.1	36,232	3.1	62.0
1988		218,195	3.0	40,332	2.0	37,162	2.6	62.6
1989		224,750	3.0	41,132	2.0	38,132	2.6	63.2
1990		230,713	2.7	42,012	2.2	39,092	2.5	63.5
GROWTH	86-90		2.8		2.1		2.7	
GROWTH	81-90		3.0		2.3		3.0	

BASED ON FORM ERA-411

TABLE 3A.9

CURRENT CAPABILITY(MW) AND RESERVES (MW AND PERCENT)

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

	1981 SUMMER	1981 WINTER
1. PLANNED CAPABILITY (MW)	46176	48771
2. PEAK DEMAND (MW)	34102	30112
3. PLANNED RESERVES (MW)(1-2)	12074	18659
4. PLANNED RESERVES (%) (3/2) X 100	35.4	62.0
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	607	107
6. TOTAL CAPABILITY (MW) (1+5)	46783	48878
7. TOTAL RESERVES (MW) (6-2)	12681	18766
8. TOTAL RESERVES (%) (7/2) X 100	37.2	62.3
9. SCHEDULED MAINTENANCE (MW)	2050	3658
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	44733	45220
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	10631	15108
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	31.2	50.2
13. FULL FORCED OUTAGES (MW)	5033	5316
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	39700	39904
15. AVAILABLE RESERVES (MW) (14-2)	5598	9792
16. AVAILABLE RESERVES (%) (15/2) X 100	16.4	32.5
17. OTHER UNAVAILABLE CAPABILITY (MW)	2229	975
18. AVAILABLE CAPABILITY (MW) (14-17)	37471	38929
19. ACTUAL RESERVES (MW) (18-2)	3369	8817
20. ACTUAL RESERVES (%) (19/2) X 100	9.9	29.3

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	1115	0
22. ACTUAL CAPABILITY (MW) (18-21)	36356	38929
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	2254	8817
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	6.6	29.3

BASED ON FORM ERA-411

BEST DOCUMENT AVAILABLE

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The projected reserves shown on Table 3A.11 are somewhat larger than the PJM Agreement criteria, but are based on timely completion of all new equipment.

To meet the projected demand increases, approximately 11,300 MW of new base load generating capacity is planned, of which about 7,600 MW will be nuclear and 4,090 MW coal-fired. The projected additions to nuclear capacity will increase its share of energy output from 20% in 1979 to about 27% in 1990. The capacity mix in 1990 is expected to be 27% nuclear, 34% coal-fired and 32% oil-fired. These figures represent a decrease of 2,000 MW as compared to schedules prepared in the 1980 report and include cancellations of 1,250 MW of nuclear capacity and 800 MW of coal-fired generating capacity.

TABLE 3A. 11

PROJECTED RESERVES

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTIONS REGION

YEAR	PLANNED RESERVES	TOTAL RESERVES	AVAILABLE RESERVES
SUMMER			
1981	35.4	37.2	16.4
1982	34.8	35.1	16.4
1983	34.2	34.5	15.8
1984	32.5	32.7	14.3
1985	31.4	31.6	13.4
1986	28.8	29.1	11.2
1987	28.0	28.2	10.4
1988	30.0	30.2	12.2
1989	28.8	29.1	11.2
1990	28.9	29.2	11.2
WINTER			
1981	62.0	62.3	32.5
1982	60.1	60.5	31.0
1983	58.1	58.5	29.4
1984	55.2	55.5	26.9
1985	52.8	53.1	25.0
1986	48.5	48.8	21.4
1987	49.1	49.4	21.9
1988	47.4	47.7	20.6
1989	45.1	45.4	18.7
1990	44.5	44.8	18.2

BASED ON FORM ERA-411

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Tables 3A.12.1 and 3A.12.2 indicate the fuel percentages for each capacity type for the years 1981 through 1990, at the time of the summer and winter peaks.

Table 3A.13 shows the major nuclear, coal, oil and hydro units planned or under construction for the region. Also shown is the schedule slippage experienced by each unit.

TABLE 3A.13

MAJOR FUTURE GENERATING UNIT IN--SERVICE DATES

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

UTILITY	PLANT NAME	NAME PLATE CAPACITY (MW)	ORIGINAL IN-SERVICE DATE	IN-SERVICE DATE AS OF APRIL 1980	PRESENT IN-SERVICE DATE
		NUCLEAR			
PSEG	SALEM #2	1115	MAR 1973	OCT 1980	APR 1981
PEPL	SUSQUEHANNA #1	1152	JAN 1979	JAN 1982	MAR 1982
PEPL	SUSQUEHANNA #2	1152	MAY 1981	JAN 1983	MAY 1983
PHEC	LIMERICK #1	1055	AUG 1978	MAY 1985	APR 1985
PSEG	HOPE CREEK #1	1067	DEC 1982	MAY 1985	DEC 1986
PHEC	LIMERICK #2	1055	MAR 1980	MAY 1987	NOV 1987
PSEG	HOPE CREEK #2	1067	DEC 1982	MAY 1987	DEC 1989
JECP	FORK RIVER #1	1251	NOV 1978	MAY 1986	CANCELLED
		COAL			
BAGE	BRANDON SHORES #1	625	JAN 1981	MAY 1984	MAY 1984
BAGE	BRANDON SHORES #2	625	MAY 1985	JAN 1988	JAN 1988
ATCE	CUMBERLAND #1	290	MAY 1988	MAY 1988	APR 1988
DEPL	VIENNA #9	500	MAY 1987	MAY 1987	MAY 1988
PEEC	SEWARD #7	625	MAY 1984	MAY 1987	MAY 1989
POEP	DICKERSON #1	800	MAR 1982	MAY 1987	CANCELLED
PEEC	COHO #1	625	MAY 1986	MAY 1989	DEFERRED
		OIL			
POEP	CHALK POINT #4	600	DEC 1981	DEC 1981	MAY 1982
		HYDRO			
BAGE	SAFE HARBOR(EXPANS)	188	OCT 1985	OCT 1985	OCT 1985
PEPL	HOLTWOOD (EXPANSION)	188	MAY 1980	-	MAY 1980

BASED ON FORM ERA-411

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Planned, under construction or committed transmission lines are listed in Table 3A.14.

TABLE 3A.14

PLANNED,UNDER CONSTRUCTION OR COMMITTED TRANSMISSION LINES

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

YEAR	VOLTAGE (KV)	MILES
EXISTING	230	4,400
1980-1984	230	482
1985-1989	230	369
TOTAL	230	5,251
EXISTING	345	160
1980-1984	345	10
1985-1989	345	6
TOTAL	345	176
EXISTING	500	1,263
1980-1984	500	337
1985-1989	500	122
TOTAL	500	1,722

BASED ON NERC 10TH ANNUAL REVIEW- AUGUST 1980

Scheduled imports for the period 1982 through 1990 consist of 107 MW of capacity from the Power Authority of the State of New York to the Allegheny Electric Cooperative. There are no scheduled exports.

TABLE 3A. 4

HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

	1977		1978		1979		1980	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	44084	44212	43748	44660	44613	44499	44752	44900
2. PEAK DEMAND (MW)	32180	27967	31686	28529	31654	27967	34525	29730
3. PLANNED RESERVES (MW)(1-2)	11904	16245	12062	16131	12959	16532	10227	15170
4. PLANNED RESERVES (%) (3/2) X 100	37.0	58.1	38.1	56.5	40.9	59.1	29.6	51.0
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	50	50	180	180	180	180	2258	3047
6. TOTAL CAPABILITY (MW) (1+5)	44134	44262	43928	44840	44793	44679	47010	47947
7. TOTAL RESERVES (MW) (6-2)	11954	16295	12242	16311	13139	16712	12485	18217
8. TOTAL RESERVES (%) (7/2) X 100	37.1	58.3	38.6	57.2	41.5	59.8	36.2	61.3
9. SCHEDULED MAINTENANCE (MW)	1035	2154	1559	4684	1459	5414	1729	3871
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	43099	42108	42369	40156	43334	39265	45281	44076
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	10919	14141	10683	11627	11680	11298	10756	14346
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	33.9	50.6	33.7	40.8	36.9	40.4	31.2	48.3
13. FULL FORCED OUTAGES (MW)	5928	6802	1907	3739	6519	8283	6768	6467
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	37171	35306	40462	36417	36815	30982	38513	37609
15. AVAILABLE RESERVES (MW) (14-2)	4991	7339	8776	7888	5161	3015	3988	7879
16. AVAILABLE RESERVES (%) (15/2) X 100	15.5	26.2	27.7	27.6	16.3	10.8	11.6	26.5
17. OTHER UNAVAILABLE CAPABILITY (MW)	2163	1871	2548	523	725	1167	1602	-1766
18. AVAILABLE CAPABILITY (MW) (14-17)	35008	33435	37914	35894	36090	29815	36911	39375
19. ACTUAL RESERVES (MW) (18-2)	2828	5468	6228	7365	4436	1848	2386	9645
20. ACTUAL RESERVES (%) (19/2) X 100	8.8	19.6	19.7	25.8	14.0	6.6	6.9	32.4

BASED ON FORM ERA-411

TABLE 3A. 10.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

	1982		1983		1984	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	47408	49935	48352	50954	48971	51578
2. PEAK DEMAND (MW)	35162	31182	36032	32222	36972	33242
3. PLANNED RESERVES (MW)(1-2)	12246	18753	12320	18732	11999	18336
4. PLANNED RESERVES (%) (3/2) X 100	34.8	60.1	34.2	58.1	32.5	55.2
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	107	107	107	107	107	107
6. TOTAL CAPABILITY (MW) (1+5)	47515	50042	48459	51061	49078	51685
7. TOTAL RESERVES (MW) (6-2)	12353	18860	12427	18839	12106	18443
8. TOTAL RESERVES (%) (7/2) X 100	35.1	60.5	34.5	58.5	32.7	55.5
9. SCHEDULED MAINTENANCE (MW)	1422	3745	1451	3822	1469	3868
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	46093	46297	47008	47239	47609	47817
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	10931	15115	10976	15017	10637	14575
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	31.1	48.5	30.5	46.6	28.8	43.8
13. FULL FORCED OUTAGES (MW)	5167	5443	5270	5554	5338	5622
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	40926	40854	41738	41685	42271	42195
15. AVAILABLE RESERVES (MW) (14-2)	5764	9672	5706	9463	5299	8953
16. AVAILABLE RESERVES (%) (15/2) X 100	16.4	31.0	15.8	29.4	14.3	26.9
17. OTHER UNAVAILABLE CAPABILITY (MW)	1754	999	1789	1019	1812	1037
18. AVAILABLE CAPABILITY (MW) (14-17)	39172	39855	39949	40666	40459	41158
19. ACTUAL RESERVES (MW) (18-2)	4010	8673	3917	8444	3487	7916
20. ACTUAL RESERVES (%) (19/2) X 100	11.4	27.8	10.9	26.2	9.4	23.8

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	1982		1983		1984	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. NUCLEAR DELAYS (MW)	1152	0	1152	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	38020	39855	38797	40666	40459	41158
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	2858	8673	2765	8444	3487	7916
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	8.1	27.8	7.7	26.2	9.4	23.8

BASED ON FORM ERA-411

TABLE 3A.10.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	49641	52283	49842	52202	50559	54011
2. PEAK DEMAND (MW)	37792	34212	38692	35162	39512	36232
3. PLANNED RESERVES (MW)(1-2)	11849	18071	11150	17040	11047	17779
4. PLANNED RESERVES (%) (3/2) X 100	31.4	52.8	28.8	48.5	28.0	49.1
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	107	107	107	107	107	107
6. TOTAL CAPABILITY (MW) (1+5)	49748	52390	49949	52309	50666	54118
7. TOTAL RESERVES (MW) (6-2)	11956	18178	11257	17147	11154	17886
8. TOTAL RESERVES (%) (7/2) X 100	31.6	53.1	29.1	48.8	28.2	49.4
9. SCHEDULED MAINTENANCE (MW)	1489	3921	1492	3915	1517	4051
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	48259	48469	48457	48394	49149	50067
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	10467	14257	9765	13232	9637	13835
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	27.7	41.7	25.2	37.6	24.4	38.2
13. FULL FORCED OUTAGES (MW)	5411	5699	5433	5690	5511	5887
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	42848	42770	43024	42704	43638	44180
15. AVAILABLE RESERVES (MW) (14-2)	5056	8558	4332	7542	4126	7948
16. AVAILABLE RESERVES (%) (15/2) X 100	13.4	25.0	11.2	21.4	10.4	21.9
17. OTHER UNAVAILABLE CAPABILITY (MW)	1837	1046	1844	1044	1871	1080
18. AVAILABLE CAPABILITY (MW) (14-17)	41011	41724	41180	41660	41767	43100
19. ACTUAL RESERVES (MW) (18-2)	3219	7512	2488	6498	2255	6868
20. ACTUAL RESERVES (%) (19/2) X 100	8.5	22.0	6.4	18.5	5.7	19.0

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. NUCLEAR DELAYS (MW)	1055	0	0	1067	0	1055
22. ACTUAL CAPABILITY (MW) (18-21)	39956	41724	41180	40593	41767	42045
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	2164	7512	2488	5431	2255	5813
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	5.7	22.0	6.4	15.4	5.7	16.0

BASED ON FORM ERA-411

TABLE 3A.10.3

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

	1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	52421	54793	52976	55328	54156	56486
2. PEAK DEMAND (MW)	40332	37162	41132	38132	42012	39092
3. PLANNED RESERVES (MW)(1-2)	12089	17631	11844	17196	12144	17394
4. PLANNED RESERVES (%) (3/2) X 100	30.0	47.4	28.8	45.1	28.9	44.5
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	107	107	107	107	107	107
6. TOTAL CAPABILITY (MW) (1+5)	52528	54900	53083	55435	54263	56593
7. TOTAL RESERVES (MW) (6-2)	12196	17738	11951	17303	12251	17501
8. TOTAL RESERVES (%) (7/2) X 100	30.2	47.7	29.1	45.4	29.2	44.8
9. SCHEDULED MAINTENANCE (MW)	1573	4109	1589	4150	1625	4236
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	50955	50791	51494	51285	52638	52357
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	10623	13629	10362	13153	10626	13265
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	26.3	36.7	25.2	34.5	25.3	33.9
13. FULL FORCED OUTAGES (MW)	5714	5972	5774	6031	5903	6157
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	45241	44819	45720	45254	46735	46200
15. AVAILABLE RESERVES (MW) (14-2)	4909	7657	4588	7122	4723	7108
16. AVAILABLE RESERVES (%) (15/2) X 100	12.2	20.6	11.2	18.7	11.2	18.2
17. OTHER UNAVAILABLE CAPABILITY (MW)	1940	1096	1960	1107	2004	1130
18. AVAILABLE CAPABILITY (MW) (14-17)	43301	43723	43760	44147	44731	45070
19. ACTUAL RESERVES (MW) (18-2)	2969	6561	2628	6015	2719	5978
20. ACTUAL RESERVES (%) (19/2) X 100	7.4	17.7	6.4	15.8	6.5	15.3

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	0	0	0	1067	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	43301	43723	43760	43080	44731	45070
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	2969	6561	2628	4948	2719	5978
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	7.4	17.7	6.4	13.0	6.5	15.3

BASED ON FORM ERA-411

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TABLE 3A. 12.1

SUMMER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

YEAR	NUCLEAR STEAM	COAL STEAM	OIL			NATURAL GAS			HYDRO		TOTAL CAPABILITY
			STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	
1981	8191	15807	11667	7066	143	358	708	0	956	1280	46176
% TOTAL	17.7	34.2	25.3	15.3	0.3	0.8	1.5	0.0	2.1	2.8	100.0
1982	9241	15824	11831	7066	143	358	708	0	957	1280	47408
% TOTAL	19.5	33.3	25.0	14.9	0.3	0.8	1.5	0.0	2.0	2.7	100.0
1983	10291	15793	11757	7066	142	358	708	0	957	1280	48352
% TOTAL	21.3	32.6	24.4	14.6	0.3	0.7	1.5	0.0	2.0	2.6	100.0
1984	10291	16413	11757	7066	141	358	708	0	957	1280	48971
% TOTAL	21.0	33.5	24.1	14.1	0.3	0.7	1.4	0.0	2.0	2.6	100.0
1985	11346	16581	11577	6692	141	358	708	0	958	1280	49641
% TOTAL	22.8	33.4	23.4	13.5	0.3	0.7	1.4	0.0	1.9	2.6	100.0
1986	11346	16581	11577	6692	154	358	708	0	1146	1280	49842
% TOTAL	22.7	33.2	23.4	13.4	0.3	0.7	1.4	0.0	2.3	2.6	100.0
1987	12413	16581	11229	6692	152	358	708	0	1146	1280	50559
% TOTAL	24.5	32.8	22.3	13.2	0.3	0.7	1.4	0.0	2.3	2.5	100.0
1988	13468	17991	10632	6692	146	358	708	0	1146	1280	52421
% TOTAL	25.7	34.3	20.3	12.8	0.3	0.7	1.3	0.0	2.2	2.4	100.0
1989	13468	18616	10632	6622	146	358	708	0	1146	1280	52976
% TOTAL	25.4	35.1	20.1	12.5	0.3	0.7	1.3	0.0	2.2	2.4	100.0
1990	14535	18616	10632	6548	145	358	708	0	1334	1280	54156
% TOTAL	26.8	34.3	19.7	12.0	0.3	0.7	1.3	0.0	2.5	2.4	100.0

BASED ON FORM ERA-411

TABLE 3A.12.2

WINTER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION REGION

			OIL			NATURAL GAS			HYDRO		
YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	TOTAL CAPABILITY
1981	8341	16105	11935	8797	146	368	841	0	958	1280	48771
% TOTAL	17.1	33.0	24.5	18.0	0.3	0.8	1.7	0.0	2.0	2.6	100.0
1982	9391	16118	12036	8796	146	368	841	0	959	1280	49935
% TOTAL	18.8	32.3	24.1	17.6	0.3	0.7	1.7	0.0	1.9	2.6	100.0
1983	10441	16087	12036	8796	146	368	841	0	959	1280	50954
% TOTAL	20.5	31.5	23.6	17.3	0.3	0.7	1.7	0.0	1.9	2.5	100.0
1984	10441	16712	12036	8796	145	368	841	0	959	1280	51578
% TOTAL	20.2	32.4	23.3	17.1	0.3	0.7	1.6	0.0	1.9	2.5	100.0
1985	11496	16882	11851	8271	145	368	841	0	1149	1280	52283
% TOTAL	22.0	32.3	22.7	15.8	0.3	0.7	1.6	0.0	2.2	2.4	100.0
1986	11496	16882	11757	8271	158	368	841	0	1149	1280	52202
% TOTAL	22.0	32.3	22.6	15.8	0.3	0.7	1.6	0.0	2.2	2.5	100.0
1987	13618	16823	11757	8019	156	368	841	0	1149	1280	54011
% TOTAL	25.2	31.1	21.8	14.8	0.3	0.7	1.6	0.0	2.1	2.4	100.0
1988	13618	18238	11130	8019	150	368	841	0	1149	1280	54793
% TOTAL	24.9	33.3	20.3	14.6	0.3	0.7	1.5	0.0	2.1	2.3	100.0
1989	13618	18863	11130	7929	150	368	841	0	1149	1280	55328
% TOTAL	24.6	34.1	20.1	14.3	0.3	0.7	1.5	0.0	2.1	2.3	100.0
1990	14685	18863	11130	7833	149	368	841	0	1337	1280	56486
% TOTAL	26.0	33.4	19.7	13.8	0.3	0.7	1.5	0.0	2.3	2.3	100.0

BASED ON FORM ERA-411

SECTION XIV.4
MID-AMERICA INTERPOOL NETWORK
(MAIN)

[redacted]

Mid-America Interpool Network (MAIN)

The Mid-America Interpool Network (MAIN) region includes all of Illinois and parts of Michigan, Wisconsin, and Missouri. The planning of construction and the utilization of generation and transmission facilities for purposes of improved reliability and adequacy of bulk power supply within the region are coordinated through a formal agreement -- the Mid-America Interpool Network (MAIN) -- which was originally signed by participants in 1964. There are 12 regular members of MAIN, composed of investor-owned, rural cooperative and municipal power suppliers, and four associate members. Collectively, these utilities represent essentially all the power resources within the region.

Additional coordination within MAIN is effected through agreements among the various utility systems and several power pooling groups. The Illinois - Missouri Pool (ILLMO); the Wisconsin Power Pool (WIPP); and the Wisconsin - Upper Michigan Systems (WUMS) comprise the three Electric Regions in MAIN.

The regular members of MAIN are arranged geographically into four groups: Commonwealth Edison; Illinois Group; Missouri Group; and the Wisconsin - Upper Michigan Systems Group. These correspond to the following DOE Electric Regions:

Electric Region 6 - Commonwealth Edison Company (CECO)
Electric Region 17 - Illinois - Missouri (ILLMO) Group
Electric Region 19 - Wisconsin - Upper Michigan Systems (WUMS) Group

MAIN does not have facilities for regional control of generating capacity or major switching stations nor are such facilities planned in the future. Each system controls its own generating capacity in accordance with procedures established by MAIN Operating Guides. A coordination center has been established to collect, coordinate and evaluate, and disseminate information on system conditions in MAIN and neighboring regions.

The principal responsibility of the Center is to assist MAIN utilities in assuring that the region will meet its load requirements with maximum interconnected system reliability. The Center has a permanent staff and computer equipment to aid in performing operating and special studies.

The results of a 1980 MAIN Summer Operating Study performed by the Center were reported in the Council's April 1, 1981, ERA-411 report. Interregional Emergency Transfer Capabilities determined from the 1980 Summer Study are given below.

Table 4.1

Emergency Transfer Capabilities 1/
(MAIN)

ECAR to MAIN	2900	MW	MAIN to ECAR	4000 +	MW
MARCA to MAIN	400	MW	MAIN to MARCA	800	MW
SERC to MAIN	1800	MW *	MAIN to SERC	2500	MW
SPP to MAIN	2400	MW	MAIN to SPP	1850	MW

NOTE: * After implementation of an operating guide.
+ Indicates capability exceeds tabulated value.

1/ Incremental above scheduled transfers.

Analyses of the three Electric Regions in MAIN follow.

A. Commonwealth Edison Company (CECO)

Electric Region 6

Historical Perspective

Electric Region 6 geographically covers the northern portion of Illinois which is essentially the service area of the Commonwealth Edison Company (CECO). In addition to Commonwealth Edison, data for two small Illinois municipal electric systems within the same geographic area are included in this report -- Rochelle, Illinois and Winnetka, Illinois. These electric systems' data are included also in the MAIN ERA-411 report.

The region has a diverse mixture of commerce, industry and agriculture. The electric systems in the region provide service to approximately eight million people in an 11,525 square mile area, including about 400 municipalities and the city of Chicago. CECO serves approximately 2.9 million customers, of which 2.6 million are residential and the remainder commercial and industrial customers. The region has 765-kV and 345 KV interconnections with the Indiana and Michigan Electric Company (AEP) in ECAR and 345 KV ties with Northern Indiana Public Service Company, also in ECAR. In addition, there are 345 KV ties with the Illinois Power Company, Central Illinois Public Service Company, Central Illinois Light Company, Wisconsin Power and Light Company and Wisconsin Electric Power Company System in MAIN, and with Iowa-Illinois Gas and Electric Company in MARCA.

CECO has approximately 40 percent of the total generating capability in MAIN and is a major subgroup of the MAIN organization.

Current Perspective

The 1981 expected summer load and supply situation for Electric Region 6 is given in Appendix C. The 1981-1982 winter situation is discussed below.

The 1981-1982 winter planned capability is estimated to be 17,033 MW and the peak demand is projected to be 11,365 MW, resulting in planned reserves of 5,668 MW or 49.9 percent. After adjustment for a new import of 624 MW from outside the region, total reserves are increased to 6,292 MW or 55.4 percent.

Scheduled maintenance, as reported in the ERA-411 report, is estimated to be 1,779 MW during the 1981-1982 winter peak period. Actual maintenance outages during the 1977-1979 winter periods averaged 11.6 percent of installed capability. Applying this historical maintenance record to the winter peak period (1,976 MW), the reserve margin is projected to be 4,316 MW or 38.0 percent. Over the summer period 1977 to 1980, forced outages amounted to 8.2 percent of the installed winter capability and other unavailable capacity averaged 15.5 percent. Based on these historical rates, forced outages are estimated to be 1,397 MW, thereby reducing the reserve margin to 2,919 MW or 25.7 percent. Adjusting for other unavailable capacity reduces the projected actual reserves to 279 MW or 2.5 percent which is considered marginal for reliability purposes. The current capability and reserve data for the 1981 winter season are shown in Table 4A.1, on the next page.

Future Perspective

Tables 4A.7.1 and 4A.7.2 show projected actual reserve margins for Region 6 over the summer and winter periods of 1982-1990. Reserves are determined using the 1977-1980 historical outage rates for scheduled maintenance, forced outages, and other unavailable capability. Both the near-term (1982-1985) and the long-term (1986-1990) summer periods show negative reserves each year which range from a - 5.7 percent (- 1,033 MW) in 1987 in 1987 to a - 15.4 percent (- 3,051 MW) in 1990, based on the assumptions stated above. MAIN as a whole has positive reserve margins each year except for a - 0.7 percent (- 240 MW) in the summer of 1982. Emergency power power could be sent to CECO from other systems within and outside of MAIN through available high-voltage interconnections. It has been customary for CECO to depend on the transmission network to supply about two-thirds of its reserve requirements and about one-third of its capability.

[redacted]

Table 4A.1

Current Capability (MW) and Reserves (MW and Percent)

Commonwealth Edison Company

	Winter 1981/1982
1. Planned Capability	17033
2. Peak Demand	11365
3. Planned Reserves (1-2)	5668
4. Planned Reserves (%) (3/2) x 100	49.9
5. Net Transactions (Imports - Exports)	624
6. Total Capability (1+5)	17657
7. Total Reserves (6-2)	6292
8. Total Reserves (%) (7/2) x 100	55.4
9. Scheduled Maintenance	1976
10. Capability After Maintenance	15681
11. Reserves After Maintenance (10-2)	4316
12. Reserves After Maintenance (11/2) x 100	38.0
13. Full Forced Outages	1397
14. Capability After Full Forced Outages (10-13)	14284
15. Reserves After Full Forced Outages (14-2)	2919
16. Reserves (%) After Full Forced Outages (15/2) x 100	25.7
17. Other Unavailable Capability	2640
18. Actual Capability (14-17)	11644
19. Actual Reserves (18-2)	279
20. Actual Reserves (%) (19/2) x 100	2.5

Based on Form ERA-411

In Table 4A.2, the results of recent operating studies indicate the nonsimultaneous Emergency Transfer Capability (ETC) between CECO and other areas.

Table 4A.2

NonSimultaneous Emergency Transfer Capability (ETC)

Commonwealth Edison Company

Area or Region		Import (MW) *	Export (MW) *
ILLMO:	Missouri	550	1,200
	South & Central Illinois	1,000	1,500 +
WUMS		900	400
MARCA:	Iowa	700	1,250
	Minnesota	500	600
ECAR		3,250	4,000 +
TVA		1,500 +	1,500 +

*Incremental above scheduled interchange.

Based on Form ERA-411

[redacted]

During the winter peak periods, both the near-term and long-term periods are projected to have positive actual reserves each year, ranging from 11.5 to 16.6 percent in the near-term and 3.3 to 17.0 percent in the long-term period. Most of these should be adequate to cover any unforeseen contingencies. As in the summer calculations, the reserve figures are determined using historical values for scheduled maintenance, forced outages and other unavailable capability as a percentage of planned capability.

In order to promote reliable service, the MAIN Council has defined a procedure for determining the minimum generating reserve requirements for the groups within MAIN. These are detailed in the MAIN Operating Guide No. 6, "Procedure for Determination of Generating Reserve Requirements." As stated in the MAIN ERA-411 report,

> Commonwealth Edison's reserve margin criteria is 15 percent during the summer and 24 percent during the winter. The reserve margin is computed by subtracting the native peak demand from the system net capability. The net of firm purchases, firm sales, diversity exchanges and the Ludington pumped storage allotment are added to owned generating capability to obtain system net capability.

A summary of forecasted and required reserve margins for the 1981-1985 period is shown in Table 4A.3. Forecasted reserve margins were extracted directly from Item 3-A, line 12 of the ERA-411 report for MAIN.

Table 4A.3

Forecasted and Required Reserve Margins

Commonwealth Edison Company

	Forecasted Reserve Margin - MW		Required Reserve Margin - MW		Excess or Deficit - MW	
Year	Summer	Winter	Summer	Winter	Summer	Winter
1981	1824	4289	2250	2719	-426	1570
1982	2272	7120	2340	2801	-68	4319
1983	2558	6687	2408	2885	150	3802
1984	3178	8362	2483	2971	695	5391
1985	3798	8002	2558	3060	1240	4942

Based on Form ERA-411

The forecasted reserve margin in each year is in excess of the required reserve except for the summers of 1981 and 1982. It is stated in the ERA-411 report that appropriate steps will be taken to eliminate these deficiencies. The reserve margins calculated herein are based upon the peak load forecast and the planned capability reported in the ERA-411 report for 1981.

Energy requirements and loads projected for the period of 1981 to 1990 are given in Table 4A.4.

Table 4A.4

Historical and Projected Energy Demands and Load Factors

Commonwealth Edison Company

	Energy Requirements		Summer Demand		Winter Demand		Annual Load Factor
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	(%)
1977	65103	-	13932	-	10726	-	53.3
1978	67927	4.3	13720	-1.5	11068	3.2	56.5
1979	67650	0.4	13804	0.6	10715	-3.2	55.9
1980	67155	-0.7	14275	3.4	10810	0.9	53.6
% Growth 1977-1980		0.1		0.8		0.3	
1981	68699	2.3	15047	5.4	11365	5.1	52.1
1982	70904	3.2	15648	4.0	11706	3.0	51.7
1983	73179	3.2	16103	2.9	12061	3.0	51.9
1984	75535	3.2	16604	3.1	12422	3.0	51.8
1985	78042	3.3	17105	3.0	12793	3.0	52.1
% Growth 1981-1985		3.1		3.7		3.4	
1986	80599	3.3	17607	2.9	13175	3.0	52.3
1987	83257	3.3	18158	3.1	13575	3.0	52.3
1988	86065	3.4	18711	3.0	13977	3.0	52.4
1989	88973	3.4	19262	2.9	14398	3.0	52.7
1990	91981	3.4	19864	3.1	14830	3.0	52.9
% Growth 1986-1990		3.3		3.0		3.0	
% Growth 1981-1990		3.2		3.4		3.2	

Based on Form ERA-411

Energy requirements are projected to grow at an annual compound rate of 3.1 percent between 1981 and 1985, at 3.3 percent between 1986 and 1990, and at 3.2 percent for the entire period, 1981-1990.

The summer demand growth rates are projected to decrease from 5.4 percent between 1980 and 1981 to 3.0 percent between 1984 and 1985 and to continue at approximately this rate through 1990. The 1980-1981 forecast estimates a higher growth rate at 5.4 percent compared to the 1979-1980 rate of 3.4 percent. The higher rate assumes an increase in regional economic activity and a return to typically hot summers from the mild ones experienced in 1978 and 1979.

The winter demand growth rates are projected to decrease from 5.1 percent between 1980 and 1981 to a 3.0 percent annual rate over the 1982-1990 period.

The regional summer and winter planned generating capabilities over the period of 1981 to 1990 are shown by type of fuel in Tables 4A.8.1 and 4A.8.2, respectively. Generation additions over the same period are shown in Table 4A.9.

[redacted]

There are currently seven nuclear reactors installed in the region totalling 4975 MW. Nuclear generating units, scheduled for installation during the 1981-1990 period are identified in Table 4A.5.

Table 4A.5

Scheduled Nuclear Additions - 1981-1990

Commonwealth Edison Company

Station	Summer (MW)	Winter (MW)	Type	Effective Date
LaSalle County 1	1048	1078	BWR 1/	04/82
LaSalle County 2	1048	1078	BWR	12/82
Byron 1	1120	1120	PWR 2/	10/83
Byron 2	1120	1120	PWR	10/84
Braidwood 1	1090	1120	PWR	10/85
Braidwood 2	1090	1120	PWR	10/86

1/ BWR- Boiling Water Reactor
2/ PWR - Pressurized Water Reactor

Based on Form ERA-411

A delay of the LaSalle County 1 unit beyond the 1982 summer peak period would further reduce forecasted reserve margins from a - 2214 MW (- 14.1%) to a - 3262 MW (- 20.8%). MAIN as a whole is projected to have a negative reserve margin during the summer 1982 peak period. Therefore, a delay in start-up of LaSalle County 1 could seriously impact regional reliability.

A similar delay of the in-service date of LaSalle County 2 beyond the winter 1982 peak would reduce forecasted reserve margins from an adequate 1342 MW (11.5%) to a marginal 265 MW (2.3%).

Transmission Capability

Table 4A.10 presents a list of proposed bulk power lines for the period January, 1981 to January, 1991.

The adequacy and reliability of the region's transmission network is evaluated periodically for contingency conditions in accordance with the MAIN Operating Guide No. 2. The results of studies for determining the 1984 ETC's for the CECO Region was reported in the ERA-411 report submitted April 1, 1980. These studies indicated that the Commonwealth Edison Company's ETC is adequate to meet the region's projected needs for 1984.

[redacted]

Table 4A.6 summarizes the projected 1984 ETC's for the CECO Region.

Table 4A.6

1984 Emergency Transfer Capability (ETC)

Commonwealth Edison Company

Import From	ETC (MW)	Limiting Element
ECAR	3400	Dumont-Babcock 345 KV
IOWA	1700	Marshfield-Clark Co. 115 KV
	1700 1/	Wien-T Corners 115 KV
	900 1/	Cassel-Wien 115 KV
	350 1/	T Corners-Wissota 115 KV
	500	Alma-Wabaco 161 KV
	450 1/	Cassel-Wien 115 KV
	200 1/	T Corners-Wissota 115 KV
	1400	Dardenne-Pike 161 KV
	1800	Ind. Park-Meredosia 138 KV
	3500	Electric Jct.-Lombard 345 KV
	1200	
	450 1/	

Export To	ETC (MW)	Limiting Element
ECAR	5000 +	No Limit Found
IOWA	800	Calamus-Maqunketa 161 KV
MINN	400	Genoa-Lacrosse Tap 161 KV
MO	1100	Cahokia 345/138 KV Trfr.
SCILL	2000 +	No Limit Found
TVA	3600	Quad Cities-Sub 91 345 KV
WUMS	900	Electric Jct.-Lombard 345 KV

1/ Limitation is not recognized as a valid constraint on transfer capability because line can be opened under emergency condition.

Based on Form ERA-411

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TABLE 4A.7.1
FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
COMMONWEALTH EDISON CO. (REGION 6)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	17547	19201	18607	20321	19727	21441	20852	22566
2. PEAK DEMAND	15648	11706	16103	12061	16604	12422	17105	12793
3. PLANNED RESERVES (1-2)	1899	7495	2504	8260	3123	9019	3747	9773
4. PLANNED RESERVES (%) (3/2)X100	12.1	64.0	15.5	68.5	18.8	72.6	21.9	76.4
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	624	624	312	312	312	312	312	312
6. TOTAL CAPABILITY (1+5)	18171	19825	18919	20633	20039	21753	21164	22878
7. TOTAL RESERVES (6-2)	2523	8119	2816	8572	3435	9331	4059	10085
8. TOTAL RESERVES (%) (7/2)X100	16.1	69.4	17.5	71.1	20.7	75.1	23.7	78.8
9. SCHEDULED MAINTENANCE	351	2227	372	2357	395	2487	417	2618
10. CAPABILITY AFTER MAINTENANCE	17820	17598	18547	18276	19644	19266	20747	20260
11. RESERVES AFTER MAINTENANCE (10-2)	2172	5892	2444	6215	3040	6844	3642	7467
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	13.9	50.3	15.2	51.5	18.3	55.1	21.3	58.4
13. FULL FORCED OUTAGES	1263	1574	1340	1666	1420	1758	1501	1850
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	16557	16024	17207	16610	18224	17508	19246	18410
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	909	4318	1104	4549	1620	5086	2141	5617
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	5.8	36.9	6.9	37.7	9.8	40.9	12.5	43.9
17. OTHER UNAVAILABLE CAPABILIY	3123	2976	3312	3150	3511	3323	3712	3498
18. ACTUAL CAPABILITY (14-17)	13434	13048	13895	13460	14713	14185	15534	14912
19. ACTUAL RESERVES (18-2)	-2214	1342	-2208	1399	-1891	1763	-1571	2119
20. ACTUAL RESERVES (%) (19/2)X100	-14.1	11.5	-13.7	11.6	-11.4	14.2	-9.2	16.6

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TABLE 4A.7.2
FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990
COMMONWEALTH EDISON Co. (REGION 6)

	1986 SUMMER	1986 WINTER	1987 SUMMER	1987 WINTER	1988 SUMMER	1988 WINTER	1989 SUMMER	1989 WINTER	1990 SUMMER	1990 WINTER
1. PLANNED CAPABILITY	21942	23686	23032	23686	23032	23686	23032	23686	23032	23686
2. PEAK DEMAND	17607	13175	18158	13575	18711	13977	19262	14398	19864	14830
3. PLANNED RESERVES (1-2)	4335	10511	4874	10111	4321	9709	3770	9288	3168	8856
4. PLANNED RESERVES (%) (3/2)X100	24.6	79.8	26.8	74.5	23.1	69.5	19.6	64.5	15.9	59.7
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	87	87	312	312	0	0	0	0	0	0
6. TOTAL CAPABILITY (1+5)	22029	23773	23344	23998	23032	23686	23032	23686	23032	23686
7. TOTAL RESERVES (6-2)	4422	10598	5186	10423	4321	9709	3770	9288	3168	8856
8. TOTAL RESERVES (%) (7/2)X100	25.1	80.4	28.6	76.8	23.1	69.5	19.6	64.5	15.9	59.7
9. SCHEDULED MAINTENANCE	439	2748	461	2748	461	2748	461	2748	461	2748
10. CAPABILITY AFTER MAINTENANCE	21590	21025	22883	21250	22571	20938	22571	20938	22571	20938
11. RESERVES AFTER MAINTENANCE (10-2)	3983	7850	4725	7675	3860	6961	3309	6540	2707	6108
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	22.6	59.6	26.0	56.5	20.6	49.8	17.2	45.4	13.6	41.2
13. FULL FORCED OUTAGES	1580	1942	1658	1942	1658	1942	1658	1942	1658	1942
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	20010	19083	21225	19308	20913	18996	20913	18996	20913	18996
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2403	5908	3067	5733	2202	5019	1651	4598	1049	4166
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	13.6	44.8	16.9	42.2	11.8	35.9	8.6	31.9	5.3	28.1
17. OTHER UNAVAILABLE CAPABILITY	3906	3671	4100	3671	4100	3671	4100	3671	4100	3671
18. ACTUAL CAPABILITY (14-17)	16104	15412	17125	15637	16813	15325	16813	15325	16813	15325
19. ACTUAL RESERVES (18-2)	-1503	2237	-1033	2062	-1898	1348	-2449	927	-3051	495
20. ACTUAL RESERVES (%) (19/2)X100	-8.5	17.0	-5.7	15.2	-10.1	9.6	-12.7	6.4	-15.4	3.3

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TABLE 4A.8.1

INSTALLED NET SUMMER CAPABILITY BY TYPE, AS OF MAY 31 - MW

COMMONWEALTH EDISON CO. (REGION 6)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	4975	6948	3248	686	31	26	569	16	0	0	16499
% TOTAL	30.2	42.0	19.7	4.2	0.2	0.2	3.4	0.1	0.0	0.0	100.0
SUMMER 1981	4975	6948	3248	686	31	26	569	16	0	0	16499
% TOTAL	30.2	42.0	19.7	4.2	0.2	0.2	3.4	0.1	0.0	0.0	100.0
SUMMER 1982	6023	6948	3248	686	31	26	569	16	0	0	17547
% TOTAL	34.3	39.7	18.5	3.9	0.2	0.1	3.2	0.1	0.0	0.0	100.0
SUMMER 1983	7071	6948	3248	686	31	26	569	28	0	0	18607
% TOTAL	37.9	37.3	17.5	3.7	0.2	0.1	3.1	0.2	0.0	0.0	100.0
SUMMER 1984	8191	6948	3248	686	31	26	569	28	0	0	19727
% TOTAL	41.5	35.2	16.5	3.5	0.2	0.1	2.9	0.1	0.0	0.0	100.0
SUMMER 1985	9311	6948	3248	686	31	26	569	28	0	0	20847
% TOTAL	44.8	33.3	15.6	3.3	0.1	0.1	2.7	0.1	0.0	0.0	100.0
SUMMER 1986	10401	6948	3248	686	31	26	569	33	0	0	21942
% TOTAL	47.4	31.7	14.8	3.1	0.1	0.1	2.6	0.2	0.0	0.0	100.0
SUMMER 1987	11491	6948	3248	686	31	26	569	33	0	0	23032
% TOTAL	49.9	30.2	14.1	3.0	0.1	0.1	2.5	0.1	0.0	0.0	100.0
SUMMER 1988	11491	6948	3248	686	31	26	569	33	0	0	23032
% TOTAL	49.9	30.2	14.1	3.0	0.1	0.1	2.5	0.1	0.0	0.0	100.0
SUMMER 1989	11491	6948	3248	686	31	26	569	33	0	0	23032
% TOTAL	49.9	30.2	14.1	3.0	0.1	0.1	2.5	0.1	0.0	0.0	100.0
SUMMER 1990	11491	6948	3248	686	31	26	569	33	0	0	23032
% TOTAL	49.9	30.2	14.1	3.0	0.1	0.1	2.5	0.1	0.0	0.0	100.0

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TABLE 4A.8.2

INSTALLED NET WINTER CAPABILITY BY TYPE OF FUEL, AS OF NOV.30 - MW

COMMONWEALTH EDISON CO. (REGION 6)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	5058	7013	3272	900	31	26	717	16	0	0	17033
% TOTAL	29.7	41.1	19.2	5.3	0.2	0.2	4.2	0.1	0.0	0.0	100.0
WINTER 1981	5058	7013	3272	900	31	26	717	16	0	0	17033
% TOTAL	29.7	41.1	19.2	5.3	0.2	0.2	4.2	0.1	0.0	0.0	100.0
WINTER 1982	6136	7013	3272	900	31	26	717	28	0	0	18123
% TOTAL	33.9	38.5	18.1	5.0	0.2	0.1	4.0	0.2	0.0	0.0	100.0
WINTER 1983	8334	7013	3272	900	31	26	717	28	0	0	20321
% TOTAL	41.1	34.5	16.1	4.4	0.2	0.1	3.5	0.1	0.0	0.0	100.0
WINTER 1984	9454	7013	3272	900	31	26	717	28	0	0	21441
% TOTAL	44.2	32.7	15.3	4.2	0.1	0.1	3.3	0.1	0.0	0.0	100.0
WINTER 1985	10574	7013	3272	900	31	26	717	33	0	0	22566
% TOTAL	46.9	31.1	14.5	4.0	0.1	0.1	3.2	0.1	0.0	0.0	100.0
WINTER 1986	11694	7013	3272	900	31	26	717	33	0	0	23686
% TOTAL	49.5	29.6	13.8	3.8	0.1	0.1	3.0	0.1	0.0	0.0	100.0
WINTER 1987	11694	7013	3272	900	31	26	717	33	0	0	23686
% TOTAL	49.5	29.6	13.8	3.8	0.1	0.1	3.0	0.1	0.0	0.0	100.0
WINTER 1988	11694	7013	3272	900	31	26	717	33	0	0	23686
% TOTAL	49.5	29.6	13.8	3.8	0.1	0.1	3.0	0.1	0.0	0.0	100.0
WINTER 1989	11694	7013	3272	900	31	26	717	33	0	0	23686
% TOTAL	49.5	29.6	13.8	3.8	0.1	0.1	3.0	0.1	0.0	0.0	100.0
WINTER 1990	11694	7013	3272	900	31	26	717	33	0	0	23686
% TOTAL	49.5	29.6	13.8	3.8	0.1	0.1	3.0	0.1	0.0	0.0	100.0

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Table 4A.9

Major Future Generating Capability Installations and Removals

Commonwealth Edison Company

Station	Unit 1/ Type	Fuel 2/ Type	Net Summer Capability	Net Winter Capability	In-Service Date 3/ 4/1/80 Report	In-Service Date 3/ 4/1/81 Report
LaSalle City 1	NB	UR	1048	1078	12/80	04/82
LaSalle City 2	NB	UR	1048	1078	12/81	12/82
Byron 1	NP	UR	1120	1120	10/82	10/83
Byron 2	NP	UR	1120	1120	10/83	10/84
Braidwood 1	NP	UR	1090	1120	10/83	10/85
Braidwood 2	NP	UR	1090	1120	10/84	10/86
Langham 2	ST	UN	550	550	10/88	10/90
Langham 1	ST	UN	550	550	04/89	-
Unidentified 1	ST	UN	550	550	10/89	-

1/ NB = Boiling Water Reactor; NP = Pressurized Water Reactor; ST = Steam.
2/ UR = Uranium; UN = Unknown at this time.
3/ Comparison of projected operating dates as reported in the April 1, 1980, and April 1, 1981, ERA-411 reports.

Based on Form ERA-411

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Table 4A.10

List of Proposed Bulk Power Lines - 1/1/81 to 1/1/91

Commonwealth Edison Company

Terminals	Line Length KM	Line Length Miles	Expected Service Date	Nominal Voltage in KV Oper	Nominal Voltage in KV Design	Notes
Braidwood - East Frankfort	58	36	05/81	345	345	Relieve Overloads
Braidwood - David Creek	37	23	05/81	345	345	Relieve Overloads
LaSalle - Plano	68	42	10/81	345	345	Deliver Generator Output
LaSalle - Plano	68	42	10/81	345	345	Deliver Generator Output
Braidwood - East Frankfort	58	36	11/81	345	345	Deliver Generator Output
Braidwood - Existing Line	8	5	11/81	345	345	Deliver Generator Output
Braidwood - Existing Line	8	5	11/81	345	345	Deliver Generator Output
Byron - Existing Line	13	8	12/82	345	345	Deliver Generator Output
Byron - Cherry Valley	35	22	03/84	345	345	Deliver Generator Output
Byron - Wempletown	48	30	03/84	345	345	Deliver Generator Output
Electric Junction - Wayne	23	14	05/84	345	345	Relieve Overloads
Braidwood - Davis Creek	37	23	05/85	345	345	Deliver Generator Output
Davis Creek - Crete	55	34	05/86	345	345	Deliver Generator Output
Davis Creek - Crete	55	34	05/86	345	345	Deliver Generator Output
Crete - Bloom	8	5	05/86	345	345	Relieve Overloads
Langham - Existing Line	6	4	10/89	345	345	Deliver Generator Output
Wayne - Itasoa	24	15	05/90	345	345	Relieve Overloads

Based on Form ERA-411

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B. Illinois - Missouri Group (ILLMO)

Electric Region 17

Electric Region 17 includes all of Illinois except the northern portion plus the eastern portion of Missouri. The major power suppliers in the region are the Central Illinois Public Service Co., Illinois Power Co., and the Union Electric Co. These three electric systems formed a formal power pool in 1952, in order to coordinate their planning and installation of generating and transmission facilities and the operation of their systems, including emergency and economy exchanges, spinning reserves, and maintenance schedules.

In addition to the three power pool systems, including their subsidiaries, data are included in this electric region for the Central Illinois Light Co.; City of Springfield, Illinois; Southern Illinois Power Cooperative; Soyland Power Cooperative; Western Illinois Power Cooperative; and the City of Columbia, Missouri.

All of the above systems report to the Mid-America Interpool Network (MAIN) organization, which oversees the coordination of planning, construction, and utilization of generation and transmission facilities of its participants in order to improve the reliability of the electric bulk power supply in the region. The utilities in the Department of Energy's Electric Region 17 are arranged geographically into the Illinois and Missouri Groups (ILLMO) of MAIN.

Utilities in the ILLMO Region serve about 1.6 million customers, of which 1.4 million are residential, 161,000 are commercial, and 8,000 are industrial customers. They have 345 KV interconnections among themselves and with utilities in other regions: in ECAR, with the Indiana - Michigan Electric Co., and the Public Service Co., of Indiana; in MARCA, with the Iowa - Illinois Gas and Electric Co., and the Iowa Southern Utilities Co.; in the Southwest Power Pool, with the Kansas Gas and Electric Co., the Public Service Company of Oklahoma, and the Kansas City Power and Light Co.; and with TVA.

Electric Energy, Inc. (EEInc) is a corporation owned by Union Electric Company (40%), Illinois Power Company (20%), Central Illinois Public Service Company (20%), in MAIN; and Kentucky Utilities Company (20%), in ECAR. EEInc operates the Joppa Power Plant with a nominal capacity of 1,000 MW and supplies a portion of the DOE plant load near Paducah, Kentucky. During the four summer months, no reserve is provided, and the sale to DOE is considered a non-firm sale. For the other eight months, a 15 percent reserve is provided and the sale to DOE is considered a firm sale. The portion of the Joppa Plant available to each of the ILLMO companies is included in their planned capability. The DOE load is not included in the area's load. Power supplying this load is handled as a transfer.

Current Perspective

The 1981 expected summer load and supply situation for Electric Region 17 is given in Appendix C. The 1981-82 winter situation is discussed below.

The 1981-82 winter planned capability is estimated to be 15,768 MW and the peak demand is projected to be 10,262 MW, resulting in planned reserves of 5,506 MW or 53.7 percent. After adjustment for a net export of 784 MW out of the region, the total reserve is decreased to 4,722 MW or 46.0 percent.

Planned scheduled maintenance is estimated to be 1,009 MW during the 1981-82 winter peak period, based on historical data of maintenance outages which occurred during the 1977-79 winter periods as a percentage of installed capability. Adjusting for the capability unavailable because of maintenance during the winter peak period, the reserve margin is projected to be 3,713 MW or 36.2 percent. Full forced outages historically amounted to 8.5 percent of the installed winter capability, and other unavailable capacity averaged 5.8 percent. Based on the historical rate, full forced outage is estimated to be 1,340 MW, thereby reducing the reserve margin to 2,373 MW or 23.1 percent. Adjusting for other unavailable capacity reduces the projected actual reserve to 1,458 MW or 14.2 percent. The current capability and reserve data for the 1981 winter season are shown in Table 4B.11.

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Future Perspective

The projected actual reserve marg s of the region for the summer and winter periods of 1982-1990 are given in Tabl .12. Scheduled maintenance, full forced outage and other unavailable capabilities e determined by using the 1977-1980 historic date. Both the near-term (1982-85) and the long-term (1986-1990) summer periods show positive reserves each year, which range from 6.8 percent (910 MW) in 1982 to 18.2 percent (2,573 MW) in 1984. The summer reserve margin in each year of the 1982-1990 period, therefore, should be adequate. In addition to generating capability installed within the region, emergency power is available through its multiple high voltage ties with other areas. Recent operating studies indicate the following Emergency Transfer Capability (ETC) between the South Central Illinois Systems (SCILL) and other areas, and between the Missouri Systems and other areas.

Table 4B.1

SCILL Nonsimultaneous ETC (MW) *

Area/ Region	Imports	Exports
CE	1,500 +	1,000
ECAR	1,500 +	950
IOWA	500	900
MINN	500	800
MO	1,500 +	850
SPP	600	1,050
TVA	950	1,000
WUMS	850	400

Missouri Nonsimultaneous ETC (MW) *

Area/ Region	Imports	Exports
CE	1,200	550
ECAR	1,200	600
IOWA	450	950
MINN	450	850
SCILL	850	1,500 +
SPP	1,200 - 1,500	750 - 1,250
TVA	900	1,050
WUMS	900	450

* Incremental above scheduled interchange.

Although there is considerable emergency transfer capability between ILLMO and other regions, a local transmission problem exists due to the delay of the Illinois Power Company's 345-KV Kansas-Sidney line. The line was originally scheduled for completion in 1977 and is currently expected to be completed no earlier than the summer of 1983. The reason for the delay is the intervention by some farm groups concerned over effective land utilization and type of structures to be used. Since this delay may cause some local outages, the systems involved have developed emergency operating plans for the affected area in order to minimize its impact on system reliability.

Both the near-term and long-term periods are projected to have positive actual reserves each year, during the winter peak periods, ranging from 12.7 percent (1,370 MW) in 1982 to 22.5 percent (2,562 MW) in 1983, in the near-term and 5.2 percent (810 MW) in 1990 to 12.1 percent (1,733 MW) in 1988 in the long-term period. These reserves should be adequate.

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In order to promote reliable service, the MAIN Council has defined a procedure for determining the minimum generation reserve requirements for the groups within MAIN, which is detailed in the MAIN Operating Guide No. 6, "Procedure for Determination of Generating Reserve Requirements." In concurrence with the Guide, the reserve margin for the systems comprising the Illinois - Missouri Pool is the greater of 15 percent of the highest forecast monthly adjusted demand (demand plus firm purchases minus firm sales) for the year, or 50 percent of the capability of the largest generating unit. A summary of forecasted and required margin for the 1981-85 period is shown in Table 4B.2.

Table 4B.2

Illinois - Missouri Pool [1]

Year	Forecasted Margin - MW Summer	Forecasted Margin - MW Winter	Required Margin - MW Summer	Required Margin - MW Winter	Excess or Deficit - MW Summer	Excess or Deficit - MW Winter
1981	2,427	2,771	1,670	1,670	757	1,101
1982	1,785	2,766	1,725	1,725	60	1,041
1983	3,115	4,254	1,775	1,775	1,340	2,479
1984	3,770	4,063	1,776	1,776	1,994	2,287
1985	3,179	3,576	1,829	1,829	1,350	1,747

As shown in Table 4B.2, the forecasted reserve in each year is in excess of the required reserve criteria; however, excess reserve or reserve in general is also dependent on availability of the fuel supply. Energy requirements and loads over the projected period are given in Table 4B.3.

Table 4B.3

Historical and Projected Energy, Demands, and Load Factors
ILLMO Region

Year	Energy Requirements (GWh)	Energy Requirements Growth (%)	Summer Demand (MW)	Summer Demand Growth (%)	Winter Demand (MW)	Winter Demand Growth (%)	Annual Load Factor (%)
1977	55,091	-	11,698	-	9,110	-	53.8
1978	56,827	3.1	11,549	(1.3)	9,286	1.9	56.2
1979	57,827	1.8	12,091	4.7	8,981	(3.3)	54.6
1980	60,327	4.3	12,946	7.1	9,761	8.7	53.2
% Growth 1977-1980		3.1		3.4		2.3	
1981	60,000	(0.5)	12,912	(0.3)	10,262	5.1	53.1
1982	62,327	3.9	13,332	3.3	10,824	5.5	53.4
1983	64,314	3.2	13,719	2.9	11,384	5.2	53.5
1984	67,181	4.5	14,116	2.9	11,909	4.6	54.3
1985	69,703	3.8	14,536	3.0	12,464	4.7	54.7
% Growth 1981-1985		3.8		3.0		5.0	
1986	72,379	3.8	14,960	2.9	13,019	4.5	55.2
1987	75,002	3.6	15,449	3.3	13,661	4.9	55.4
1988	77,779	3.7	15,895	2.9	14,270	4.5	55.9
1989	80,512	3.5	16,334	2.8	14,885	4.3	56.3
1990	83,237	3.4	16,797	2.8	15,502	4.1	56.5
% Growth 1986-1990		3.6		2.9		4.5	
% Growth 1981-1990		3.7		3.0		4.7	

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[1] ILLMO Pool members only

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The 1981-85 energy requirements are projected to grow at a compound rate of 3.8 percent; 1986-1990, 3.6 percent; and overall 1981-1990, 3.7 percent.

The 1981-85 summer demands are projected to grow at 3.0 percent and the 1986-1990 at 2.9 percent, with an overall 1981-1990 growth of 3.0 percent. The annual load factors increase from 53.1 percent in 1981 to 56.6 percent in 1990.

The winter demands are projected to grow at 5.0 percent during the 1981-85 period, 4.5 percent during the 1986-1990 period, and 4.7 percent over the 1981-1990 period. These rates are considerably higher than the historic 1977-1980 rate of 2.3 percent.

The summer and winter capability of generating units planned in the region for the period 1981-1990 are shown by type of fuel in Table 4B.13. Generating unit additions during the period are indicated on Table 4B.14. The summer capability by type of fuel use for the target years 1981, 1985, and 1990 are given below.

Table 4B.4

Planned Summer Generating Capability by Type of Fuel - Percent
ILLMO Region

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			ST	CT	IC	ST	CT	IC	Conv.	P.S.	
1981											
MW	-	13,081	1,183	630	38	-	113	-	333	300	15,678
% Total	-	83.4	7.6	4.0	0.3	-	0.7	-	2.1	1.9	100.0
1985											
MW	2,100	13,850	1,108	630	38	-	113	-	333	300	18,472
% Total	11.4	75.0	6.0	3.4	0.2	-	0.6	-	1.8	1.6	100.0
1990											
MW	3,250	14,905	1,108	730	38	-	113	-	333	300	20,777
% Total	15.6	71.9	5.3	3.5	0.2	-	0.5	-	1.6	1.4	100.0

There are currently no nuclear units installed in the region, but three are under construction. The following nuclear generating units are scheduled for installation during the 1981-1990 period.

Table 4B.5

Scheduled Nuclear Additions - (1981-1990)
ILLMO Region

System	Station	Summer (MW)	Type	Effective Date
UNEC	Callaway 1	1,150	PWR	4/83
ILPC*	Clinton 1	950	BWR	8/83
UNEC	Callaway 2	1,150	PWR	4/88

*Clinton 1 is jointly owned by Illinois Power Co. (760 MW), Soyland Power Cooperative (100 MW), and Western Illinois Power Cooperative (90 MW).

The Callaway 1 unit is included in the summer 1983 planned capability, but the Clinton 1 unit is not; and the Callaway 2 unit is included in the summer 1988 planned capability. If the Callaway 1 and 2 units were delayed beyond their respective peak periods, the projected actual reserve margin would be reduced to 905 MW (6.6%) in the summer of 1983 and to 1,289 MW (8.1%) in the summer of 1988. In either case, the reserve margin would still be sufficient.

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In addition to the nuclear units, a new 577 MW coal unit is included in the 1982 winter planned capability; a new 450 MW unit is included in the 1986 summer capability, a new 350 MW is included in the 1988 winter planned capability; and a new 450 MW unit is included in the 1990 winter capability. Delay of each of these units beyond the respective year's peak periods would reduce the projected actual reserve margin to 793 MW (7.3%) in the 1982 winter; to 1,419 MW (9.5%) in the 1986 summer; to 1,383 MW (9.7%) in the 1988 winter; and to 360 MW (2.3%) in the 1990 winter. Except for 1990, the reserve margin should be adequate.

Transmission Capability

The adequacy and reliability of the region's transmission network is tested periodically for contingency conditions in accordance with MAIN Operating Guide No. 2.

Using the criteria of MAIN Operating Guide No. 2, the 1984 South Central Illinois System's (SCILL) area was tested to determine interchange capabilities with other areas. The results of this investigation were reported in the ERA-411 Report submitted April 1, 1980. The results indicated that SCILL emergency transfer capabilities (ETC) are judged to be adequate; however, some are lower than desired.

The following tabulation summarizes SCILL's emergency import capability for 1984.

Table 4B.6

1984 Emergency Transfer Capability - Imports
ILLMO Region - (SCILL)

Import From	ETC (MW)	Limiting Facility
CE	2000 +	No Limit Found
ECAR	1900 (a)	Bunsonville - Eugene 345 KV
IOWA	100	Lakeshire - Watson 138 KV
MINN	150	Lakeshire - Watson 138 KV
MO	550	Meramec 3 - Lemay Tap 138 KV
SPP	100	Lakeshire - Watson 138 KV
TVA	2500 +	No Limit Found
WUMS	1300 (b)	Zion - Pleasant Prairie 345 KV

(a) The Bunsonville - Eugene 345 KV line is scheduled to be upgraded in 1982. However, the present MVA rating has been used in this study to determine the most restrictive case.

(b) WUMS to SCILL emergency transfers are restricted by the Waukegan to Kenosha 138 KV line.

According to the study, the ETC into SCILL from IOWA, MINN, MO, and SPP are lower than desired. These limitations are due to the Lakeshire - Watson and Meramec 3 - Lemay Tap 1, 138 KV lines. The area that encompasses these lines has been under review by Union Electric.

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The following tabulation summarizes SCILL's emergency export capability for 1984.

Table 4B.7

1984 Emergency Transfer Capability - Exports
ILLMO Region - (SCILL)

Export To	ETC (MW)	Limiting Facility
CE	1800	Industrial Park - Meredosia 138 KV
ECAR	1600	Industrial Park - Meredosia 138 KV
IOWA	800	Maryville - St. Joseph 161 KV
MINN	350	Genoa - Lac Tap 161 KV
MO	1000	Cahokia 345/138 KV Xfmr
SPP	1600 (a)	Montgomery 345/161 KV Xfmr
TVA	1600	Industrial Park - Meredosia 138 KV
WUMS	800	Electric Junction - Lombard 345 KV

(a) SCILL to SPP emergency transfers are restricted by the Montgomery - Montgomery Tap 161 KV line.

The ETC limits of SCILL are judged acceptable. However, SCILL's ETC to MINN is lower than desired.

From the results of the study, it appears that with presently planned generation and transmission additions, import capabilities under ETC criteria are adequate to meet MO's needs in 1984 except from the IOWA and MINN areas. Imports from these areas are limited by the facilities outside the MO area. Export capabilities under ETC criteria seem to be adequate except to the MINN and SCILL areas.

The following tabulation summarizes MO's emergency import capability for 1984.

Table 4B.8

1984 Emergency Transfer Capability - Imports
ILLMO Region - (MO Area)

Import From	ETC (MW)	Limiting Facility
CE	1100	Cahokia 345/138 KV Xfmr.
ECAR	1100	Cahokia 345/138 KV Xfmr.
IOWA	500	St. Joe 345/161 KV Xfmr.
MINN	450 (a)	Alma - Wabco 161 KV
SCILL	1000	Cahokia 345/138 KV Xfmr.
SPP	2000	Cahokia 345/138 KV Xfmr.
TVA	1200	Cahokia 345/138 KV Xfmr.
WUMS	1300 (b)	Cahokia 345/138 KV Xfmr.

(a) MINN to MO transfers are limited to 250 MW by the T Corners - Wissota 115 KV line.

(b) WUMS to MO transfers are limited to 500 MW by the Waukegan - Kenosha 138 KV line.

It can be seen that MO's import capability is limited from all directions except IOWA and MINN by the Cahokia 345/138 KV Transformer #9 (560 MVA). The limitation is based on the emergency rating of this transformer.

The following tabulation summarizes MO's emergency export capability for 1984.

Table 4B.9

1984 Emergency Transfer Capability - Exports
ILLMO Region (MO Area)

Export To	ETC (MW)	Limiting Facility
CE	1400	Dardenne - Pike 161 KV
ECAR	2700	Turkey Hill - New Memphis Tap 138 KV
IOWA	900 (a)	Sycamore - Montezuma 345 KV
MINN	400	Genoa - LaCross Tap 161 KV
SCILL	550	Meramec 3 - Lemay Tap 1 138 KV
SPP	1500 (a)	Clark 138/161 KV Xfmr.
TVA	1900	Clark 138/161 KV Xfmr.
WUMS	800 (b)	Electric Junction - Lombard 345 KV

(a) MO to IOWA transfers are limited to 400 MW by the Montgomery - Mongtomery Tap 161 KV line. The same line limits MO to SPP transfers to zero MW. However, the emergency rating of this 0.2 mile-long line is limited by terminal equipment; and hence it is considered a local problem, which is expected to be corrected.

(b) MO to WUMS transfers are limited to 400 MW by the Corners - Wissota 115 KV line.

The following table is a list of proposed bulk power lines to be constructed in the region during the period January 1, 1981, to January 1, 1991. The purpose for construction of each line is noted.

Table 4B.10

Illinois - Missouri Group (Region 17)

List of Proposed Bulk Power Lines - 1/1/81 to 1/1/91

Line Ownership List	Terminals	Line Length KM	Line Length Miles	Expected Service Date	Nominal Voltage in KV Oper	Nominal Voltage in KV Design	Notes
ILPC	W. Kansas - Sidney	57.1	35.5	06/83	345	345	Relieve Overloads
CEIL	Duck Creek - Fargo	55	34	12/85	345	345	Deliver Generator Output
CEIP	Sidney - Paxton	61	38	03/86	345	345	Provide Area Protection
ILPO	Maroa W. - Oreana	13.5	8.4	06/88	345	345	Relieve Overloads
UNEC	Montgomery - Callaway 8	37	23	10/81	345	345	Deliver Generator Output
UNEC	Callaway - Bland 1	48	30	10/81	345	345	NRC - Separate Facility Requirement; Deliver Generator Output
UNEC	Mason - Sioux Tap - Belt	18	11	05/86	345	345	Relieve Overloads
UNEC	Callaway - Bland 2	18	30	03/88	345	345	Deliver Generator Output

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Table 4B.11

Current Capability (MW) and Reserves (MW and Percent) Illinois - Missouri Group (Region 17)

		1980-81 Winter Peak
1.	Planned Capability	15,768
2.	Peak Demand	10,262
3.	Planned Reserve (1-2)	5,506
4.	Planned Reserve (%) (3/2) x 100	53.7
5.	Net Transactions (Imports - Exports)	- 784
6.	Total Capability (1+5)	14,984
7.	Total Reserve (6-2)	4,722
8.	Total Reserve (%) (7/2) x 100	46.0
9.	Scheduled Maintenance 1/	1,009
10.	Capability After Maintenance	13,975
11.	Reserve After Maintenance (10-2)	3,713
12.	Reserve After Maintenance (%) (11/2) x 100	36.2
13.	Full Forced Outages 1/	1,340
14.	Capability After Full Forced Outages (10-13)	12,635
15.	Reserve After Full Forced Outages (14-2)	2,373
16.	Reserve (%) After Full Forced Outages (15/2) x 100	23.1
17.	Other Unavailable Capability 1/ 2/	915
18.	Actual Capability (14-17)	11,720
19.	Actual Reserve (18-2)	1,458
20.	Actual Reserve (%) (19/2) x 100	14.2

1/ Scheduled maintenance, other unavailable capability and full forced outages are calculated using the historical percent averages at the time of the winter peaks beginning with the 1977 winter data obtained from Form FPC-12E2.

2/ Other unavailable capability is that capability which is unavailable for load for reasons other than scheduled maintenance or full forced outages.

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FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
ILLINOIS-MISSOURI GROUP (REGION 17)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	15778	16365	17448	18575	18443	18508	18468	18535
2. PEAK DEMAND	13332	10824	13719	11384	14116	11909	14536	12464
3. PLANNED RESERVES (1-2)	2446	5541	3729	7191	4327	6599	3932	6071
4. PLANNED RESERVES (%) (3/2)X100	18.3	51.2	27.2	63.2	30.7	55.4	27.1	48.7
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-211	-784	-208	-784	-205	-559	-427	-559
6. TOTAL CAPABILITY (1+5)	15567	15581	17240	17791	18238	17949	18041	17976
7. TOTAL RESERVES (6-2)	2235	4757	3521	6407	4122	6040	3505	5512
8. TOTAL RESERVES (%) (7/2)X100	16.8	43.9	25.7	56.3	29.2	50.7	24.1	44.2
9. SCHEDULED MAINTENANCE 1/	237	1047	262	1189	277	1185	277	1186
10. CAPABILITY AFTER MAINTENANCE	15330	14534	16978	16602	17961	16764	17764	16790
11. RESERVES AFTER MAINTENANCE (10-2)	1998	3710	3259	5218	3845	4855	3228	4326
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	15.0	34.3	23.8	45.8	27.2	40.8	22.2	34.7
13. FULL FORCED OUTAGES 1/	252	1391	279	1579	295	1573	295	1575
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	15078	13143	16699	15023	17666	15191	17469	15215
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1746	2319	2980	3639	3550	3282	2933	2751
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	13.1	21.4	21.7	32.0	25.1	27.6	20.2	22.1
17. OTHER UNAVAILABLE CAPABILIY 1/ 2/	836	949	925	1077	977	1073	979	1075
18. ACTUAL CAPABILITY (14-17)	14242	12194	15774	13946	16689	14118	16490	14140
19. ACTUAL RESERVES (18-2)	910	1370	2055	2562	2573	2209	1954	1676
20. ACTUAL RESERVES (%) (19/2)X100	6.8	12.7	15.0	22.5	18.2	18.5	13.4	13.4

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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TABLE 4B.12 SHEET 2 OF 2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990
ILLINOIS-MISSOURI GROUP (REGION 17)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	18868	18935	19355	19424	20505	20924	20748	20819	20748	21269
2. PEAK DEMAND	14960	13019	15449	13661	15895	14270	16334	14885	16797	15502
3. PLANNED RESERVES (1-2)	3908	5916	3906	5763	4610	6654	4414	5934	3951	5767
4. PLANNED RESERVES (%) (3/2)X100	26.1	45.4	25.3	42.2	29.0	46.6	27.0	39.9	23.5	37.2
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-454	-589	-451	-589	-448	-589	-445	-589	-442	-554
6. TOTAL CAPABILITY (1+5)	18414	18346	18904	18835	20057	20335	20303	20230	20306	20715
7. TOTAL RESERVES (6-2)	3454	5327	3455	5174	4162	6065	3969	5345	3509	5213
8. TOTAL RESERVES (%) (7/2)X100	23.1	40.9	22.4	37.9	26.2	42.5	24.3	35.9	20.9	33.6
9. SCHEDULED MAINTENANCE 1/	283	1212	290	1243	308	1339	311	1332	311	1361
10. CAPABILITY AFTER MAINTENANCE	18131	17134	18614	17592	19749	18996	19992	18898	19995	19354
11. RESERVES AFTER MAINTENANCE (10-2)	3171	4115	3165	3531	3854	4726	3658	4013	3198	3852
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	21.2	31.6	20.5	25.8	24.2	33.1	22.4	27.0	19.0	24.8
13. FULL FORCED OUTAGES 1/	302	1609	310	1651	328	1779	332	1770	332	1808
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	17829	15525	18304	15941	19421	17217	19660	17128	19663	17546
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2869	2506	2855	2280	3526	2947	3326	2243	2866	2044
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	19.2	19.2	18.5	16.7	22.2	20.7	20.4	15.1	17.1	13.2
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1000	1098	1026	1127	1087	1214	1100	1208	1100	1234
18. ACTUAL CAPABILITY (14-17)	16829	14427	17278	14814	18334	16003	18560	15920	18563	16312
19. ACTUAL RESERVES (18-2)	1869	1408	1829	1153	2439	1733	2226	1035	1766	813
20. ACTUAL RESERVES (%) (19/2)X100	12.5	10.8	11.8	8.4	15.3	12.1	13.6	7.0	10.5	5.2

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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TABLE 4B.13

INSTALLED NET SUMMER CAPABILITY BY TYPE, AS OF MAY 31 - MW

ILLINOIS-MISSOURI GROUP (REGION 17)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	0	13051	1183	575	38	0	113	0	333	300	15597
% TOTAL	0.0	83.8	7.6	3.7	0.2	0.0	0.7	0.0	2.1	1.9	100.0
SUMMER 1981	0	13081	1183	620	38	0	113	0	333	300	15678
% TOTAL	0.0	83.6	7.5	4.0	0.2	0.0	0.7	0.0	2.1	1.9	100.0
SUMMER 1982	0	13196	1183	620	38	0	113	0	333	300	15793
% TOTAL	0.0	83.6	7.5	4.0	0.2	0.0	0.7	0.0	2.1	1.9	100.0
SUMMER 1983	1150	13781	1128	620	38	0	113	0	333	300	17473
% TOTAL	6.6	78.9	6.5	3.6	0.2	0.0	0.6	0.0	1.9	1.7	100.0
SUMMER 1984	2100	13891	1128	620	38	0	113	0	333	300	18533
% TOTAL	11.3	75.0	6.1	3.4	0.2	0.0	0.6	0.0	1.8	1.6	100.0
SUMMER 1985	2100	13850	1108	620	38	0	113	0	333	300	18472
% TOTAL	11.4	75.0	6.0	3.4	0.2	0.0	0.6	0.0	1.8	1.6	100.0
SUMMER 1986	2100	14250	1108	655	38	0	113	0	333	300	18897
% TOTAL	11.1	75.3	5.9	3.5	0.2	0.0	0.6	0.0	1.8	1.6	100.0
SUMMER 1987	2100	14700	1108	655	38	0	113	0	333	300	19347
% TOTAL	10.9	75.9	5.7	3.4	0.2	0.0	0.6	0.0	1.7	1.6	100.0
SUMMER 1988	3250	14687	1108	705	38	0	113	0	333	300	20534
% TOTAL	15.8	71.5	5.4	3.4	0.2	0.0	0.6	0.0	1.6	1.5	100.0
SUMMER 1989	3250	15037	1108	705	38	0	113	0	333	300	20884
% TOTAL	15.6	72.0	5.3	3.4	0.2	0.0	0.5	0.0	1.6	1.4	100.0
SUMMER 1990	3250	14905	1108	720	38	0	113	0	333	300	20777
% TOTAL	15.6	71.9	5.3	3.5	0.2	0.0	0.5	0.0	1.6	1.4	100.0

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TABLE 48.13

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INSTALLED NET WINTER CAPABILITY BY TYPE OF FUEL, AS OF NOV.30 - MW

ILLINOIS-MISSOURI GROUP (REGION 17)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	0	13041	1202	675	38	0	125	0	327	225	15637
% TOTAL	0.0	83.5	7.7	4.3	0.2	0.0	0.8	0.0	2.1	1.4	100.0
WINTER 1981	0	13119	1202	735	38	0	125	0	327	225	15775
% TOTAL	0.0	83.2	7.6	4.7	0.2	0.0	0.8	0.0	2.1	1.4	100.0
WINTER 1982	0	13205	1202	735	38	0	125	0	327	225	15861
% TOTAL	0.0	83.2	7.6	4.7	0.2	0.0	0.8	0.0	2.1	1.4	100.0
WINTER 1983	2100	13792	1144	735	38	0	125	0	327	225	18490
% TOTAL	11.4	74.5	6.2	4.0	0.2	0.0	0.7	0.0	1.8	1.2	100.0
WINTER 1984	2100	13872	1122	735	38	0	125	0	327	225	18548
% TOTAL	11.3	74.8	6.0	4.0	0.2	0.0	0.7	0.0	1.8	1.2	100.0
WINTER 1985	2100	13858	1122	766	38	0	125	0	327	225	18561
% TOTAL	11.3	74.7	6.0	4.1	0.2	0.0	0.7	0.0	1.8	1.2	100.0
WINTER 1986	2100	14258	1122	766	38	0	125	0	327	225	18961
% TOTAL	11.1	75.2	5.9	4.0	0.2	0.0	0.7	0.0	1.7	1.2	100.0
WINTER 1987	2100	14695	1122	818	38	0	125	0	327	225	19450
% TOTAL	10.8	75.5	5.8	4.2	0.2	0.0	0.6	0.0	1.7	1.2	100.0
WINTER 1988	3250	15045	1122	818	38	0	125	0	327	225	20950
% TOTAL	15.5	71.7	5.4	3.9	0.2	0.0	0.6	0.0	1.6	1.1	100.0
WINTER 1989	3250	14913	1122	845	38	0	125	0	327	225	20845
% TOTAL	15.6	71.4	5.4	4.1	0.2	0.0	0.6	0.0	1.6	1.1	100.0
WINTER 1990	3250	14913	1122	845	38	0	125	0	327	225	20845
% TOTAL	15.6	71.4	5.4	4.1	0.2	0.0	0.6	0.0	1.6	1.1	100.0

Table 4B.14

Major Future Generating Capability Installations and Removals
Illinois - Missouri Group (Region 17)

DOE/ERA Electric Region	System	Station	Unit Type	Fuel Type	Net Summer Capability (MW)	Net Winter Capability (MW)	In-Service Date 1/ 04/01/80 Report	In-Service Date 1/ 04/01/81 Report
6	CEIP	Newton #2	ST	COL	575	577	12/82	12/82
6	UNEC	Callaway #1	NP 2/	UR	1,150	1,150	10/82	04/83
6	ILPC	Clinton #1	NB 3/	UR	950	950	12/82	08/83
6	CEIL	Duck Creek #2	ST	COL	400	400	03/86	03/86
6	UNCE	Callaway #2	NP 2/	UR	1,150	1,150	04/88	04/88
6	SOIP	Marion #5	ST	COL	350	350	09/88	09/88
6	ILPC	Undetermined	ST	COL	450	450	-	01/91

Note: Jointly owned by ILPC (760 MW), SYPC (100 MW) and WEIL (90 MW).

1/ Comparison of scheduled in-service dates in the April 1, 1980, and April 1, 1981. Regional Reliability Council Reports.
2/ Pressurized Water Reactor.
3/ Boiling Water Reactor.

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C. WISCONSIN-UPPER MICHIGAN SYSTEMS GROUP (WUMS) ELECTRIC REGION 19

Electric Region 19 includes the eastern portion of Wisconsin and all of Upper Michigan except for the small portion at the eastern end which is in the ECAR region. The major power suppliers in the region are the Wisconsin Electric Power Co., Wisconsin Power and Light Co., Wisconsin Public Service Corp., and Madison Gas and Electric Company. At year-end 1980, collectively, the four companies owned about 88% of the total capacity in the region and served about 1.48 million customers, of which 1.29 million are residential customers. Of the remainder, about 44,000 are farm customers, 119,000 are commercial customers, and 1260 are industrial customers. These electric systems are interconnected with 345 kV ties as well as at lower voltages. The systems also have 345 kV ties with the Commonwealth Edison Co., (ER6-CECO) and with Northern States Power Co. in the MARCA region.

The above-listed companies, except for the Wisconsin Electric Power Co., are members of the Wisconsin Power Pool (WIPP) Group. The participants in the WIPP coordinate their planning and installation of generating and transmission facilities and the operation of their systems, including emergency and economy exchanges, spinning reserves and maintenance schedules.

The WIPP systems are also members of the Wisconsin-Upper Michigan Systems (WUMS). In addition to the three WIPP members, the Wisconsin Electric Power Co. and the Upper Peninsula Power Co. are participants in WUMS. WUMS is primarily concerned with the reliability and adequacy of power supply of its members, whereas WIPP primarily is concerned with the economy of supply for its members. WIPP members have constructed several joint power projects to achieve their objectives.

All of the members of WUMS are members of the MAIN organization and WUMS is a major subgroup of MAIN. Other systems located geographically within the WUMS region which report to MAIN are: Kaukauna, WI., Menasha, WI., Manitowoc, WI., Marshfield, WI., and Marquette, MI. Data for these systems are included in this report for WUMS.

Current Perspective

The 1981 expected summer load and supply situation for Electric Region 19 is discussed in Appendix C. The 1981-1982 winter situation is discussed below, and the data are shown in Table 4C.7.

The 1981-1982 winter planned capability is estimated to be 9,192 MW and the peak demand is projected to be 7022 MW, resulting in planned reserves of 2,120 MW or 30.0 percent. After adjustment for a net export of 8 MW, the total reserve is decreased to 2,112 MW or 29.9 percent.

Planned scheduled maintenance is estimated in the MAIN ERA-411 report to be 347 MW during the 1981-1982 winter peak period. However, actual maintenance outages during the 1977-1979 winter periods have averaged 7.8 percent of installed capability. Therefore the scheduled maintenance shown in Table 4C.7 is shown as 717 MW (= .078 x 9192). This magnitude of maintenance during the winter peak period would reduce the reserve margin to 1,395 MW or 19.7 percent. Full forced outages historically have amounted to 4.6 percent of the installed winter capability (=423 MW), thereby reducing the reserve margin to 972 MW or 13.7 percent. Adjustment for other unavailable capacity (349 MW) reduces the projected actual reserves to 623 MW or 8.8 percent.

Future Perspective

The projected actual reserve margins of the region for the summer and winter periods of 1982-1990, shown in Table 4C.8, were determined using the 1977-1980 historic outage rates for scheduled maintenance, full forced outages, and other unavailable capability. Both the near-term (1982-1985) and the long-term (1986-1990) summer periods show positive reserves each year which range from 13.4 percent (1,043 MW) in 1985 to 4.3 percent (378 MW) in 1990, based on the assumptions stated above and the planned capability, loads, imports and exports reported in the MAIN ERA report dated April 1, 1981.

In addition to its own generating capability, the WUMS region has available to it emergency power through the MAIN bulk power transmission system. Recent operating studies indicate Emergency Transfer Capability (ETC) between WUMS and other areas as shown in Table 4C.1.

Table 4C.1

Area	Nonsimultaneous ETC (MW)*	
	WUMS Imports	WUMS Exports
CE	400 (1)	900
MINN	350 (1)	500
SCILL (2)	400 (1)	850
IOWA	500 (1)	650
MO	450 (1)	900 (1)

* Incremental above scheduled interchange.

(1) After implementation of operating guides.
(2) South Central Illinois

The near-term period projection is for positive actual reserves each year, during the winter peak periods, ranging from 2.8 to 9.9 percent. These should be sufficient to cover unforeseen contingencies. The reserves figures were determined using historic values for scheduled maintenance, full forced outages and other unavailable capability as a percentage of planned capability. During the 1986-1990 period, the winter actual reserve margins are projected to be negative in 1987 through 1990, ranging from a negative 0.4 percent (34 MW) in 1987 to a negative 3.4 percent (301 MW) in 1988, if the historic percent values for scheduled maintenance, full forced outages and other unavailable capability should again be experienced. MAIN as a whole has enough surplus reserves in those years to supply the WUMS deficits.

In order to promote reliable service, the MAIN Council has defined a procedure for determining the minimum generation reserve requirements for the groups within MAIN, which is detailed in the MAIN Operating Guide No. 6, "Procedure for Determination of Generating Reserve Requirements." In agreement with the Guide, the WUMS margin criterion is 15 percent of its adjusted demand. Based on this requirement, the WUMS reserve margin in both the summer and winter periods of each year of the 1982-1990 period is sufficient.

[redacted]

The reserves required are dependent upon (among other factors) the peak load forecast and the planned capability. For reliability, even when sufficient capacity is available, an adequate supply of fuel must also be available. Energy requirements and loads over the projected period are given in Table 4C.2.

Table 4C.2

Historical and Projected Energy Demands and Load Factors
WUMS Region

	Annual Energy Requirements 1/		Seasonal Peak Demands 1/				Annual Load 2/ Factor
			Summer		Winter		
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	
1977	34,601	-	6,499	-	6,011	-	60.8
1978	37,128	7.3	6,450	(0.8)	6,266	4.2	65.7
1979	38,398	3.4	6,510	0.9	6,310	0.7	67.3
1980	38,688	(0.8)	6,694	2.8	6,495	2.9	65.8
% Growth 1977-80		3.8		1.0		2.6	
1981	40,593	4.9	7,034	5.1	3,072	8.9	65.5
1982	42,009	3.5	7,227	2.7	7,301	3.2	65.7
1983	43,316	3.1	7,414	2.6	7,543	3.3	65.6
1984	44,537	2.8	7,578	2.2	7,765	2.9	65.3
1985	45,712	2.6	7,764	2.5	8,023	3.3	65.0
% Growth 1981-85		3.4		3.0		4.3	
1986	47,032	2.9	7,971	2.7	8,293	3.4	64.7
1987	48,395	2.9	8,174	2.5	8,562	3.2	64.5
1988	49,696	2.7	8,362	2.3	8,820	3.0	64.1
1989	50,939	2.5	8,562	2.4	9,118	3.4	63.8
1990	52,387	2.8	8,772	2.5	9,388	3.0	63.7
% Growth 1986-90		2.8		2.5		3.0	
% Growth 1981-90		3.1		2.7		3.8	

1/ From 12E-2 and ERA-411 reports
2/ Computed from data in the adjoining columns

The 1981-1985 energy requirements are projected to grow at a compound rate of 3.4 percent; 1986-1990, 2.8 percent; and overall 1981-1990 3.1 percent. These rates are reduced from that of the 1977-1980 period (3.8%).

Although the region has been summer-peaking, the 1981 winter demand is projected to be slightly greater than the preceding summer peak. This pattern is expected to continue in subsequent years. The effective 1981-1985 summer demand growth rate is projected to be 3.0 percent and the 1986-1990 rate, 2.5 percent. The overall rate 1981 through 1990 is 2.7 percent. The initial higher rate forecast for 1981 (5.1 percent) compared to the actual 1980 rate (2.8 percent) assumes an increase in economic activity in the area, which has been depressed for several years, and a return to typically hot summers from the mild ones experienced in 1978 and 1979. If this higher growth in 1981 does not occur, the reserve margin will be greater than shown in Table 4C.8.

The effective 1981-85 winter demand growth rate is projected to be 4.3 percent and the 1986-1990 rate, 3.0 percent. The overall rate throughout the 1981-1990 period is 3.8 percent. Although higher than the historical 1977-1980 growth rates, the projected rates may not be unreasonable. The higher rate in 1981 (8.2 percent) compared to the actual 1980 rate (2.9) assumes an increase in the area's economy and colder winter than experienced the last two years, which were relatively mild.

[redacted]

The summer and winter capability of installed generating units in the region for the period 1981-1990 is shown by type of fuel on Table 4C.9. The winter capability by type of fuel use for the years 1981, 1985 and 1990 is given below.

Table 4C.3

Planned Winter Generating Capability by Type of Fuel
WUMS Region

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro.		Total Capability
			ST	CT	IC	ST	CT	IC	Conv.	P.S.	
1981											
MW	1515	6053	325	784	47	10	202	-	239	-	9,175
% Total	16.5	66.0	3.5	8.6	0.5	0.1	1.2	-	2.6	-	100.0
1985											
MW	1515	7320	60	784	47	10	202	-	239	-	10,177
% Total	14.9	71.9	0.6	7.7	0.5	0.1	2.0	-	2.3	-	100.0
1990											
MW	1515	7665	60	784	37	10	202	-	239	-	10,512
%Total	14.4	72.8	0.6	7.5	0.4	0.1	1.9	-	2.3	-	100.0

There are currently three nuclear reactors installed in the region totalling 1,515 MW. There are no new nuclear generating units scheduled for installation during the 1981-1990 period. There are, however, several coal-fired units scheduled as shown below.

Table 4C.4

Scheduled Coal Unit Additions - 1981-1990
WUMS Region

System	Station	Summer MW	Winter MW	Effective Date	Included In Planned Capability
WIPS	Weston 3	300	300	3/82	Summer 1982
WIPL	Edgewater 5 1/	285	285	3/84	Summer 1984
WIEP	Edgewater 5 1/	95	95	3/84	Summer 1984
WIEP	Pleasant Prairie 2	580	580	10/84	Winter 1984
WIPS	Unknown	400	400	6/89	Summer 1989
WIEP	Unknown	400	400	6/89	Winter 1990

1/ Shared Unit

If the above units were delayed beyond the start of their respective peak seasons the summer 1982 reserve margin would be reduced from 963 MW (13.3%) to 663 MW (8.6%); the summer 1984 reserve margin would be reduced from 714 MW (9.4%) to 334 MW (4.4%); the winter 1984 reserve margin would be reduced from 766 MW (9.9%) to 186 MW (2.4%); and the summer 1989 reserve margin would be reduced from 589 MW (6.90) to 189 MW (2.2%).

Transmission Capability

The adequacy and reliability of the region's transmission network is tested periodically for contingency conditions in accordance with MAIN operating Guide No. 2. The results of the investigation for the 1984 Emergency Transfer Capabilities (ETC's) of the WUMS area were reported in MAIN's ERA 411 report submitted April 1, 1981, and are shown in Table 4C.5 below.

[redacted]

Table 4C.5

1984 Emergency Transfer Capability (ETC)
WUMS Region

Import From	ETC (MW)	Limiting Element
CE	900	Electric Junction - Lombard 345 kV
IOWA	800	Electric Junction - Lombard 345 kV
MINN	600	Alma-Wabaco - 161 kV
MO	800	Electric Jct. - Lombard 345 kV
SCILL *	800	Electric Jct. - Lombard 345 kV
Export To		
CE	1,200	Zion-Pleasant Prairie 345 kV
IOWA	800	Sycamore - Montezuma 345 kV
MINN	500	Genoa - LaCrosse 161 kV
MO	1,300	Cahokia 345/138 Kv transformer
SCILL *	1,300	Zion - Pleasant Prairie 345 kV

* South Central Illinois

The following table is a list of proposed bulk power lines to be constructed in the region during the period January 1, 1981 to January 1, 1991. The purpose of each line is noted.

Table 4C.6

Wisconsin-Upper Michigan Systems Group (Region 19)
List of Proposed 345 kV Bulk Power Lines - 01/01/81 to 01/01/91

Terminals	Utility	Line Length Miles	Expected Service Date	Notes
Paddock-Paddock Tap	WIPL	0.4	06/84	a,b
Paddock-Paddock Tap	WIPL	0.4	06/84	a,b
Pleasant Prairie-Arcadian	WIEP	54	10/84	c
Brookdale-Granville	WIEP	14	06/86	a
Brookdale-Racine	WIEP	31	06/86	a
Venus-Plains	1/	64	06/88	a
Black Brook-Venus	WIPS	32	06/88	b
Wesbay-Existing	WIEP	27	06/88	a
Wesbay-Existing	WIPS	7	06/88	a

1/ WIEP & WIPS

WIPL = Wisconsin Power & Light
WIEP = Wisconsin Electric Power
WIPS = Wisconsin Public Service

a - Provide Area Protection
b - Relieve Overloads
c - Deliver Generator Output

[redacted]

Table 4C.7

Current Capability (MW) and Reserves (MW and Percent)

Wisconsin-Upper Michigan Systems Group (Region 19)

		1981/82 Winter Peak
1.	Planned Capability	9,192
2.	Peak Demand	7,072
3.	Planned Reserves (1-2)	2,120
4.	Planned Reserves (%) (3/2)x100	30.0
5.	Net Transactions (Imports-Exports)	-8
6.	Total Capability (1+5)	9,184
7.	Total Reserves (6-2)	2,112
8.	Total Reserves (%) (7/2)x100	29.9
9.	Scheduled Maintenance /1/	717
10.	Capability After Maintenance (6-9)	8,467
11.	Reserves After Maintenance (10-2)	1,395
12.	Reserves After Maintenance (%) (11/2)x100	19.7
13.	Full Forced Outages /1/	423
14.	Capability After Full Forced Outages (10-13)	8,044
15.	Reserves After Full Forced Outages (14-2)	972
16.	Reserves (%) After Full Forced Outages (15/2)x100	13.7
17.	Other Unavailable Capability /1/ /2/	349
18.	Actual Capability (14-17)	7,695
19.	Actual Reserves (18-2)	623
20.	Actual Reserves (%) (19/2)x100	8.8

/1/ Scheduled maintenance, other unavailable capability and full forced outages are calculated using the historical percent averages at the time of the winter peaks beginning with the 1977 winter. Data obtained from FPC Form-12E2.

/2/ Other unavailable capability is that capability which is unavailable for load for reasons other than scheduled maintenance or full forced outages.

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TABLE 4C.8 SHEET 1 OF 2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
WISCONSIN-UPPER MICHIGAN SYSTEMS GROUP (REGION 19)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	9214	9532	8993	9267	9334	10194	9914	10194
2. PEAK DEMAND	7227	7301	7414	7543	7578	7764	7764	8023
3. PLANNED RESERVES (1-2)	1987	2231	1579	1724	1756	2430	2150	2171
4. PLANNED RESERVES (%) (3/2)X100	27.5	30.6	21.3	22.9	23.2	31.3	27.7	27.1
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-10	-9	-11	-10	-16	-13	-16	-14
6. TOTAL CAPABILITY (1+5)	9204	9523	8982	9257	9318	10181	9898	10180
7. TOTAL RESERVES (6-2)	1977	2222	1568	1714	1740	2417	2134	2157
8. TOTAL RESERVES (%) (7/2)X100	27.4	30.4	21.1	22.7	23.0	31.1	27.5	26.9
9. SCHEDULED MAINTENANCE /1/	479	743	468	723	485	795	516	795
10. CAPABILITY AFTER MAINTENANCE	8725	8780	8514	8534	8833	9386	9382	9385
11. RESERVES AFTER MAINTENANCE (10-2)	1498	1479	1100	991	1255	1622	1618	1362
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	20.7	20.3	14.8	13.1	16.6	20.9	20.8	17.0
13. FULL FORCED OUTAGES /1/	120	438	117	426	121	469	129	469
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	8605	8342	8397	8108	8712	8917	9253	8916
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1378	1041	983	565	1134	1153	1489	893
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	19.1	14.3	13.3	7.5	15.0	14.9	19.2	11.1
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	415	362	405	352	420	387	446	387
18. ACTUAL CAPABILITY (14-17)	8190	7980	7992	7756	8292	8530	8807	8529
19. ACTUAL RESERVES (18-2)	963	679	578	213	714	766	1043	506
20. ACTUAL RESERVES (%) (19/2)X100	13.3	9.3	7.8	2.8	9.4	9.9	13.4	6.3

Based on MAIN ERA-411 Report dated April 1, 1981

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

TABLE 4C.8 SHEET 2 OF 2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990
WISCONSIN-UPPER MICHIGAN SYSTEMS GROUP (REGION 19)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	9914	10194	9914	10194	9904	10184	10304	10584	10304	10929
2. PEAK DEMAND	7972	8288	8174	8562	8362	8821	8562	9118	8772	9388
3. PLANNED RESERVES (1-2)	1942	1906	1740	1632	1542	1363	1742	1466	1532	1541
4. PLANNED RESERVES (%) (3/2)X100	24.4	23.0	21.3	19.1	18.4	15.5	20.3	16.1	17.5	16.4
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	208	211	-18	-15	-18	-15	-19	-16	-20	-17
6. TOTAL CAPABILITY (1+5)	10122	10405	9896	10179	9886	10169	10285	10568	10284	10912
7. TOTAL RESERVES (6-2)	2150	2117	1722	1617	1524	1348	1723	1450	1512	1524
8. TOTAL RESERVES (%) (7/2)X100	27.0	25.5	21.1	18.9	18.2	15.3	20.1	15.9	17.2	16.2
9. SCHEDULED MAINTENANCE /1/	516	795	516	795	515	794	536	826	536	852
10. CAPABILITY AFTER MAINTENANCE	9606	9610	9380	9384	9371	9375	9749	9742	9748	10060
11. RESERVES AFTER MAINTENANCE (10-2)	1634	1322	1206	822	1009	554	1187	624	976	672
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	20.5	16.0	14.8	9.6	12.1	6.3	13.9	6.8	11.1	7.2
13. FULL FORCED OUTAGES /1/	129	469	129	469	129	468	134	487	134	503
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	9477	9141	9251	8915	9242	8907	9615	9255	9614	9557
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1505	853	1077	353	880	86	1053	137	842	169
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	18.9	10.3	13.2	4.1	10.5	1.0	12.3	1.5	9.6	1.8
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	446	387	446	387	446	387	464	402	464	415
18. ACTUAL CAPABILITY (14-17)	9031	8754	8805	8528	8796	8520	9151	8853	9150	9142
19. ACTUAL RESERVES (18-2)	1059	466	631	-34	434	-301	589	-265	378	-246
20. ACTUAL RESERVES (%) (19/2)X100	13.3	5.6	7.7	-0.4	5.2	-3.4	6.9	-2.9	4.3	-2.6

Based on MAIN ERA-411 Report dated April 1, 1981

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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TABLE 4C.9

SHEET 1 OF 2

INSTALLED NET SUMMER CAPABILITY BY TYPE, AS OF MAY 31 - MW

WISCONSIN-UPPER MICHIGAN SYSTEMS GROUP (REGION 19)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	1508	5986	329	626	47	10	170	0	236	0	8912
% TOTAL	16.9	67.3	3.7	7.0	0.5	0.1	1.9	0.0	2.6	0.0	100.0
SUMMER 1981	1508	5976	329	626	47	10	170	0	236	0	8902
% TOTAL	16.9	67.2	3.7	7.0	0.5	0.1	1.9	0.0	2.7	0.0	100.0
SUMMER 1982	1508	6276	329	626	47	10	170	0	236	0	9202
% TOTAL	16.4	68.2	3.6	6.8	0.5	0.1	1.8	0.0	2.6	0.0	100.0
SUMMER 1983	1508	6316	68	626	47	10	170	0	236	0	8981
% TOTAL	16.8	70.3	0.8	7.0	0.5	0.1	1.9	0.0	2.6	0.0	100.0
SUMMER 1984	1508	6665	61	626	47	10	170	0	236	0	9323
% TOTAL	16.2	71.5	0.7	6.7	0.5	0.1	1.8	0.0	2.5	0.0	100.0
SUMMER 1985	1508	7245	61	626	47	10	170	0	236	0	9903
% TOTAL	15.2	73.2	0.6	6.3	0.5	0.1	1.7	0.0	2.4	0.0	100.0
SUMMER 1986	1508	7245	61	626	47	10	170	0	236	0	9903
% TOTAL	15.2	73.2	0.6	6.3	0.5	0.1	1.7	0.0	2.4	0.0	100.0
SUMMER 1987	1508	7245	61	626	47	10	170	0	236	0	9903
% TOTAL	15.2	73.2	0.6	6.3	0.5	0.1	1.7	0.0	2.4	0.0	100.0
SUMMER 1988	1508	7245	61	626	37	10	170	0	236	0	9893
% TOTAL	15.2	73.3	0.6	6.3	0.4	0.1	1.7	0.0	2.4	0.0	100.0
SUMMER 1989	1508	7245	61	626	37	10	170	0	236	0	9893
% TOTAL	15.2	73.3	0.6	6.3	0.4	0.1	1.7	0.0	2.4	0.0	100.0
SUMMER 1990	1508	7590	61	626	37	10	170	0	236	0	10238
% TOTAL	14.7	74.1	0.6	6.1	0.4	0.1	1.7	0.0	2.3	0.0	100.0

Based on MAIN ERA-411 Report dated April 1, 1981

TABLE 4C.9 SHEET 2 OF 2

INSTALLED NET WINTER CAPABILITY BY TYPE OF FUEL, AS OF NOV.30 - MW

WISCONSIN-UPPER MICHIGAN SYSTEMS GROUP (REGION 19)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	1516	6054	325	785	47	10	203	0	240	0	9180
% TOTAL	16.5	66.0	3.5	8.6	0.5	0.1	2.2	0.0	2.6	0.0	100.0
WINTER 1981	1516	6054	325	785	47	10	203	0	240	0	9180
% TOTAL	16.5	66.0	3.5	8.6	0.5	0.1	2.2	0.0	2.6	0.0	100.0
WINTER 1982	1516	6394	325	785	47	10	203	0	240	0	9520
% TOTAL	15.9	67.3	3.4	8.2	0.5	0.1	2.1	0.0	2.5	0.0	100.0
WINTER 1983	1516	6394	61	785	47	10	203	0	240	0	9256
% TOTAL	16.4	69.0	0.7	8.5	0.5	0.1	2.2	0.0	2.6	0.0	100.0
WINTER 1984	1516	7321	61	785	47	10	203	0	240	0	10183
% TOTAL	14.9	71.8	0.6	7.7	0.5	0.1	2.0	0.0	2.4	0.0	100.0
WINTER 1985	1516	7321	61	785	47	10	203	0	240	0	10183
% TOTAL	14.9	71.8	0.6	7.7	0.5	0.1	2.0	0.0	2.4	0.0	100.0
WINTER 1986	1516	7321	61	785	47	10	203	0	240	0	10183
% TOTAL	14.9	71.8	0.6	7.7	0.5	0.1	2.0	0.0	2.4	0.0	100.0
WINTER 1987	1516	7321	61	785	47	10	203	0	240	0	10183
% TOTAL	14.9	71.8	0.6	7.7	0.5	0.1	2.0	0.0	2.4	0.0	100.0
WINTER 1988	1516	7321	61	785	37	10	203	0	240	0	10173
% TOTAL	14.9	71.9	0.6	7.7	0.4	0.1	2.0	0.0	2.4	0.0	100.0
WINTER 1989	1516	7666	61	785	37	10	203	0	240	0	10518
% TOTAL	14.4	72.8	0.6	7.5	0.4	0.1	1.9	0.0	2.3	0.0	100.0
WINTER 1990	1516	7666	61	785	37	10	203	0	240	0	10518
% TOTAL	14.4	72.8	0.6	7.5	0.4	0.1	1.9	0.0	2.3	0.0	100.0

Based on MAIN ERA-411 Report dated April 1, 1981

SECTION XIV.5

MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT
(MARCA)

[redacted]

Mid-Continent Area Reliability Coordination Agreement (MARCA)
A. Mid-Continent Area Power Pool (MAPP)
Electric Region 20

The Mid-Continent Area Reliability Coordination Agreement (MARCA) was organized in 1968. It is one of the nine regional reliability councils comprising the National Electric Reliability Council (NERC). The MARCA region covers all of the states of Iowa, Minnesota, Nebraska, North Dakota, most of South Dakota, and portions of the states of Illinois, Montana, and Wisconsin.

The MARCA organization provides an overview of the planning and operating activities in the region with respect to reliability and adequacy of power supply. It presently has a membership of 28 systems consisting of 12 investor-owned utilities, 9 G&T cooperatives, 3 public power districts, 3 municipal utilities, and 1 federal agency.

Manitoba Hydro-Electric Board, a Canadian utility, is a "Liaison Member" of MARCA, and Saskatchewan Power Corporation, also a Candian utility, is an "Associate Member". The data in this report refers only to the U.S. members of MARCA, except for international power transfers.

Utilities in the U.S. portion of MARCA have about 4 million customers and serve a population of about 15 million. In terms of geographic areas, MARCA is the second largest of the 9 Regional Electric Reliability Councils. The extensive transmission system has over 2000 miles of DC transmission at ± 400 KV, some 3500 miles of 345 KV AC transmission and about 9000 miles of 230 KV AC transmission.

The Mid-Continent Area Power Pool (MAPP) is a regional power pool covering the same geographical area as MARCA and includes the same members. The Canadian utilities referred to above are not members of MAPP. The difference in the two organizations is in their objective. MAPP's purpose is to promote the development of economy of service, as well as reliable and environmentally acceptable facilities. Rate schedules for various classes of service have been established for MAPP members and are on file with the Federal Energy Regulatory Commission (FERC).

MARCA does not have facilities for regional control of generating capacity or major switching stations nor are such facilities planned for the future. Its regional operating practices and policies are established by the Mid-Continent Area Power Pool (MAPP) Operating Committee and are implemented by each system control center working in close cooperation with the MAPP Coordination Center located in Minneapolis, Minnesota. The principal responsibility of the center is to assure that the region will meet its load requirements with maximum reliability. The center has permanent staff and computer equipment to aid in performing operating and special studies. Recent seasonal operating studies performed by the center indicate that the MARCA bulk power system is capable of supplying firm requirements with enough excess transfer capability for scheduling significant amounts of emergency and economy energy.

Coordination of MARCA with the Mid-America Interpool Network (MAIN) and the Southwest Power Pool (SPP) is effected through the Inter-Regional Agreement among MAIN, MARCA and SPP which was developed and approved during 1980 and formally implemented January 14, 1981. The Agreement establishes a means for the three councils to exchange information concerning plans and forecasts in each area related to bulk power supply reliability in the other areas, and for review and analysis of such information. A Review Committee and designated subcommittee will discharge the responsibilities of the Agreement. A letter of agreement has been signed with the Western Systems Coordinating Council (WSCC) which provides for inter-regional planning, and operating liaison, and planning coordination committees as required.

[redacted]

Inter-regional non-simultaneous emergency transfer capabilities (ETC) with the MAIN region have been derived from operating studies conducted jointly with the MAIN operating studies group. The results of the winter 1980-1981 operating study are shown below.

Table 5A.1
Emergency Transfer Capability

Import From	ETC (MW)
MAIN	1200
SPP	500
Export to	
MAIN	400
SPP	900

Another major coordinating group besides MAPP within Electric Region 20 is the MBSG (Missouri Basin Systems Group). The MBSG conducts long-range power studies for its members with the objective of assuring that generation and transmission facilities are planned in the most efficient and economical manner. The MBSG coordinates closely with DOE's Western Area Power Administration (WAPA). A Joint Transmission System (JTS) has been established which is a jointly planned, jointly-owned system administered by MBSG and operated by WAPA.

The MAPP region is in the second year of drought conditions. This is not expected to affect firm power committments of WAPA this year but may impact the amount of available "dump" power which can be sold by WAPA.

Load and capability data for the following MAPP systems are included in this assessment of the adequacy of power supply of the region.

Basin Electric Power Cooperative
Cooperative Power Association
Dairyland Power Cooperative
Eastern Iowa Light and Power Cooperative
Heartland Consumers Power District
Interstate Power Company
Iowa Electric Light and Power Company/
  Central Iowa Power Cooperative
Iowa-Illinois Gas and Electric Company
Iowa Public Service Company/
  Corn Belt Power Cooperative
Iowa Southern Utilities Company
Lake Superior Distric Power Company
Lincoln Electric System
Minnesota Power and Light Company
Minnkota Power Cooperative, Inc.
Missouri Basin Municipal Power Agency
Montana-Dakota Utilities Co.
Muscatine Power and Water
Nebraska Public Power District
Northern States Power Company
Northwest Iowa Power Cooperative
Northwestern Public Service Company
Omaha Public Power District
Otter Tail Power Company
United Power Association
Western Area Power Administration -
  Billings Area

Current Perspective

The 1981 expected summer load and supply situation for Electric Region 20 is given in Appendix C. The 1981-1982 winter planned capability is estimated to be 29,061 MW and the peak demand is projected to be 18,424 MW, resulting in planned reserves of 10,637 MW or 57.7 percent. After adjustment for a net export of 410 MW out of the region, the total reserve is decreased to 10,227 MW or 55.5 percent.

[redacted]

Planned scheduled maintenance is estimated by MARCA in its ERA-411 Report to be 827 MW during the 1981-1982 winter peak periods. However, actual maintenance outages during the 1977-1979 winter periods have averaged 4.3 percent of installed capability. Adjusting for the capability unavailable because of maintenance during the winter peak period (1,250 MW) based on the average historic rate, the reserve margin is projected to be 8,977 MW or 48.7 percent. Full forced outages historically amounted to 6.8 percent of the installed winter capability and other unavailable capacity averaged 2.0 percent. Based on the historical rate, full forced outages are estimated to be 1,976 MW or 34.8 percent, which are available for other contingencies. The current capability and reserve data for the 1981 winter season are shown in table 5A.2.

TABLE 5A.2

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PRESENT) MID-CONTINENT AREA POWER POOL (REGION 20)

		1981/82 WINTER PEAK
1.	Planned Capability	29061
2.	Peak Demand	18424
3.	Planned Reserves (1-2)	10637
4.	Planned Reserves (%) (3/2) x 100	57.7
5.	Net Transactions (Imports-Exports)	-410
6.	Total Capability (1+5)	28651
7.	Total Reserves (6-2)	10227
8.	Total Reserves (%) (7/2) x 100	55.5
9.	Scheduled Maintenance /1/	1250
10.	Capability After Maintenance	27401
11.	Reserves After Maintenance (10-2)	8977
12.	Reserves After Maintenance (%) (11/2) x 100	48.7
13.	Full Forced Outages /1/	1976
14.	Capability After Full Forced Outages (10-13)	25425
15.	Reserves After Full Forced Outages (14-2)	7001
16.	Reserves (%) After Full Forced Outages (15/2) x 100	38.0
17.	Other Unavailable Capability /1/ /2/	581
18.	Actual Capability (14-17)	24844
19.	Actual Reserves (18-2)	6420
20.	Actual Reserves (%) (19/2) x 100	34.8

/1/ Scheduled maintenance, other unavailable capability and full forced outages are calculated using the historical percent averages at the time of the winter peaks beginning with the 1977 winter data obtained from FPC Form-12E2.

/2/ Other unavailable capability is that capability which is unavailable for load for reasons other than scheduled maintenance or full forced outages.

[redacted]

Nebraska Public Power District's Gentleman Unit #2 is presently scheduled to begin commercial operation in November 1981. If the in-service date of this 600 MW plant were delayed beyond the 1981-82 winter peak, the reserve margin for that season would be reduced to 5,820 MW, or 20.0 percent. This margin is considered adequate.

Future Perspective

The projected actual reserve margins of the region for the summer and winter periods of 1982-1990 were determined using the 1977-1980 historic outage rates for scheduled maintenance, full forced outages, and other unavailable capability (see Table 5A.7. Despite its relatively cold climate, MARCA has been a consistently summer-peaking region because of irrigation and air-conditioning loads. Actual reserve margins for the near term (1982-1985) summer periods range from 18.0 percent in 1985 to 24.7 percent in 1983. Actual reserves for the long term (1986-1990) summer periods declined from 17.9 percent in 1986 to 9.2 percent in 1990. The corresponding reserves in megawatts for these last two figures are 4,378 MW and 2,582 MW, respectively.

The winter peak periods are projected to have positive reserve margin each year, ranging from 23.8 percent to 29.5 percent in the near-term and from 8.9 to 20.4 percent in the long-term period. These should be sufficient to cover other contingencies. Energy requirements and loads over the projected period are given in Table 5A.6 and planned generating capability by type of fuel is given in Table 5A.8.

The 1981-1985 energy requirements are projected to grow at a compound rate of 4.8 percent; 1986-1990, 3.7 percent; and overall 1981-1990, 4.2 percent. These rates, appear to be reasonable.

The summer demand growth rates are projected to peak in 1982 at 4.8 percent, and thereafter decline to 3.5 percent in 1986. After 1986 summer growth rates cover between 3.2 and 3.5 percent. The winter growth rates reflect a similar trend, peaking in 1981 at 5.3 percent and thereafter dropping to values between 3.4 and 3.7 percent for the years 1986-1990.

The summer and winter capability of generating units planned in the region for the period 1981-1990 is shown by type of fuel on Table 5A.7. Generating unit additions during the period are indicated on Table 5A.9. The summer capability by type of fuel use for the target years 1981, 1985 and 1990 are given below.

Table 5A.3

Planned Summer Generating Capability by Type of Fuel
MAPP Region

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Total Capability
			ST	CT	IC	ST	CT	IC	Conv.	P.S.	
1981											
MW	3,720	16,315	577	2,932	284	213	72	27	3,000	-	27,140
% Total	13.7	60.1	2.1	10.8	1.0	0.8	0.3	0.1	11.0	0.0	100.0
1985											
MW	3,720	19,210	577	2,958	243	213	72	27	2,961	-	29,981
% Total	12.4	64.1	1.9	9.9	0.8	0.7	0.2	0.1	9.9	0.0	100.0
1990 MW	3,720	21,854	564	2,958	234	213	72	27	2,876	-	32,518
% Total	11.4	67.2	1.7	9.1	0.7	0.7	0.2	0.1	8.8	0.0	100.0

There are currently nine nuclear units in the region supplying 3,720 MW of power. There are no nuclear generating units scheduled for installation during the 1982-1990 period. However, there are several new coal-fired units planned for installation during the same period. The following table shows the amount of new capacity scheduled to be in service during each season and the effect on the reserve margins if these units were delayed beyond the peak occurrence of the season.

[redacted]

Table 5A.4
Effect of Delay of New Units on Reserve Margins
MAPP Region

	1982		1983		1984		1985	
	S	W	S	W	S	W	S	W
Reserves (MW) 1/	4,865	5,693	5,404	5,905	4,645	5,012	4,246	5,454
Scheduled Capacity (MW)	-	700	-	1,057	-	-	800	416
Reserve Minus Schedule Capacity (MW)	4,865	4,993	5,404	4,848	4,645	5,012	3,446	5,038
Reserves (%)	23.2	25.9	24.7	24.0	20.4	23.8	14.6	22.9

	1986		1987		1988		1989		1990	
	S	W	S	W	S	W	S	W	S	W
Reserves (MW) 1/	4,378	4,645	3,895	3,745	3,598	3,818	3,347	3,090	2,582	34
Scheduled Capacity (MW)	650	125	-	320	200	675	-	200	-	25
Reserves Minus Schedule Capacity (MW)	3,728	4,520	3,895	3,425	3,398	3,143	3,347	2,890	2,582	109
Reserves (%)	15.2	19.9	15.4	14.6	13.0	12.9	12.4	11.4	9.2	8.1

1/ Actual Reserve

It can be seen from the above table that there would be adequate reserves each season even if the new units were delayed beyond the peak occurence of the seasons.

As shown in Table 5A.8, the region depends largely on coal as the primary fuel for its generating plants. About 2500 MW of hydro capacity is installed in eight Federal projects located in the Missouri River Basin in the states of Montana, North Dakota, and South Dakota. The power output of these projects is marketed by DOE's Western Area Power Administration (WAPA).

Baseload oil capability is insignificant, comprising only 577 MW, or 2% of the current regional capability. However, there is a considerable amount of oil-fired combustion turbine capability (2,930 MW). To conserve oil, MAPP systems import hydro energy from Manitoba Hydro in Canada.

The reserve capability of the region is influenced by the emergency transfer capability of its transmission system.

Regulatory delays of proposed of bulk power transmission lines and problems in obtaining rights of way have impacted the reliability of the region. The April 1, 1981 ERA 411 report requested each reliability council to report Critical Bulk Power Transmission Facilities that will not be in service when required. The following table lists those lines reported by MARCA.

[redacted]

Table 5A.5

System	Critical Facility	In-Service Date Required	 Expected	Voltage (kV) Operating/Design
BEPC	Logan-Boundary Dam	1981	1982	230/230

Reason for Delay

Problems obtaining right-of-way.

CPA/ UPA	Dickinson-Wilmarth	11/80	11/83	345/345

Reason for Delay

The Minnesota Supreme Court ruled that the line will be subject to a rehearing by the Minnesota Energy Agency. After the Certificate of Need has been reapproved, further judicial review will be required.

This delay reduces the Coal Creek plant rating.

DPC	Genoa-Lasing	1978	1982	161/161

Reason for Delay

Denial of permits by Fish and Wildlife Service for the primary route river crossing. An alternate route is being pursued.

NPPD	Hoskins-Raun	06/80	06/82	345/345

Reason for Delay

Right-of-way acquisition.

NSP	Prairie Island-Eau Claire	1982	1984	345/345

Reason for Delay

The regulatory process pushed the in-service data back to 1984. This delay requires operation of gas turbine generation to maintain reliability to loads which are to be served by this line. Also, the delay prolongs present limitations to power transfers.

NSP	Watertown-Split Rock	05/81	11/81	345/345

Reason for Delay

Regulatory delays have caused this facility to miss the summer of 1981 in-service date. This will result in less reliable service to the Sioux Falls, South Dakota area, and require the operation of oil fired generation for area protection.

NSP	Split Rock-Sioux City	05/81	11/81	345/345

Reason for Delay

Regulatory delays have caused this facility to miss the summer of 1981 in-service date. This will result in less reliable service to the Sioux Falls, South Dakota area, and require the operation of oil fired generation for area protection.

[redacted]

Also, the ERA-411 Report requested the reporting of light load system analysis studies. In response to this request, MARCA reported the results of two light load studies in item 6B of their submission. The first study, completed in 1978, covered the summer seasons of 1981, and 1985. The second study was completed in March 1981 and covers the summer of 1982.

The studies together disclosed no problems with the transmission network at 70%-80% loading. When the load is increased to 100% of capability, the only problem reported is a required power factor restriction to between .98 and 100 on the 161 KV network.

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TABLE 5A.6

HISTORICAL AND PROJECTED ENERGY, DEMANDS AND LOAD FACTORS

REGION 20 - MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (MARCA)

	ENERGY REQUIREMENTS		SUMMER DEMAND		WINTER DEMAND		ANNUAL LOAD FACTOR
	(GWH)	GROWTH(%)	(MW)	GROWTH(%)	(MW)	GROWTH(%)	(%)
1977	85738	-	17549	-	15454	-	55.8
1978	92477	7.9	17596	0.3	16243	5.1	60.0
1979	96518	4.4	18011	2.4	17332	6.7	61.2
1980	96422	-0.1	19412	7.8	17498	1.0	56.5
% GROWTH 1977-80		4.0		3.4		4.2	
1981	101052	4.8	20039	3.2	18424	5.3	57.6
1982	106648	5.5	20995	4.8	19281	4.7	58.0
1983	111516	4.6	21909	4.4	20166	4.6	58.1
1984	116492	4.5	22810	4.1	21075	4.5	58.1
1985	121850	4.6	23626	3.6	21972	4.3	58.9
% GROWTH 1981-85		4.8		4.0		4.7	
1986	126577	3.9	24459	3.5	22757	3.6	59.1
1987	131211	3.7	25256	3.3	23546	3.5	59.3
1988	135736	3.4	26137	3.5	24358	3.4	59.1
1989	140516	3.5	26986	3.2	25245	3.6	59.4
1990	145920	3.8	27930	3.5	26168	3.7	59.6
% GROWTH 1986-90		3.7		3.4		3.6	
% GROWTH 1981-90		4.2		3.7		4.1	

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FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
MID-CONTINENT AREA POWER POOL (REGION 20)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	27633	29131	29327	30322	29499	30351	29946	31863
2. PEAK DEMAND	20595	19281	21909	20166	22810	21075	23626	21972
3. PLANNED RESERVES (1-2)	6638	9850	7418	10156	6689	9276	6320	9891
4. PLANNED RESERVES (%) (3/2)X100	31.6	51.1	33.9	50.4	29.3	44.0	26.8	45.0
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	714	-340	625	-279	610	-288	621	-263
6. TOTAL CAPABILITY (1+5)	28347	28791	29952	30043	30109	30063	30567	31600
7. TOTAL RESERVES (6-2)	7352	9510	8043	9877	7299	8988	6941	9628
8. TOTAL RESERVES (%) (7/2)X100	35.0	49.3	36.7	49.0	32.0	42.6	29.4	43.8
9. SCHEDULED MAINTENANCE /1/	525	1253	557	1304	560	1305	569	1378
10. CAPABILITY AFTER MAINTENANCE	27822	27538	29395	28739	29549	28758	29998	30230
11. RESERVES AFTER MAINTENANCE (10-2)	6827	8257	7486	8573	6739	7683	6372	8258
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	32.5	42.8	34.2	42.5	29.5	36.5	27.0	37.6
13. FULL FORCED OUTAGES /1/	1465	1981	1554	2062	1563	2064	1587	2167
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	26357	25557	27841	26677	27986	26694	28411	28063
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	5762	6276	5932	6511	5176	5619	4785	6091
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	25.5	32.6	27.1	32.3	22.7	26.7	20.3	27.7
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	497	583	528	606	531	607	539	637
18. ACTUAL CAPABILITY (14-17)	25860	24974	27313	26071	27455	26087	27872	27426
19. ACTUAL RESERVES (18-2)	4865	5693	5404	5905	4645	5012	4246	5454
20. ACTUAL RESERVES (%) (19/2)X100	23.2	29.5	24.7	29.3	20.4	23.8	18.0	24.8

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990

MID-CONTINENT AREA POWER POOL (REGION 20)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	30999	31962	31029	32193	31618	33157	32292	33356	32483	33566
2. PEAK DEMAND	24459	22757	25256	23546	26137	24358	26986	25245	27930	26168
3. PLANNED RESERVES (1-2)	6540	9205	5773	8647	5481	8799	5306	8111	4553	7398
4. PLANNED RESERVES (%) (3/2)X100	26.7	40.4	22.9	36.7	21.0	36.1	19.7	32.1	16.3	28.3
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	628	-374	916	-685	963	-637	947	-652	953	-668
6. TOTAL CAPABILITY (1+5)	31627	31588	31945	31508	32581	32520	33239	32704	33436	32898
7. TOTAL RESERVES (6-2)	7168	8831	6689	7962	6444	8162	6253	7459	5506	6730
8. TOTAL RESERVES (%) (7/2)X100	29.3	38.8	26.5	33.8	24.7	33.5	23.2	29.5	19.7	25.7
9. SCHEDULED MAINTENANCE /1/	589	1374	590	1384	601	1426	614	1434	627	1443
10. CAPABILITY AFTER MAINTENANCE	31038	30214	31355	30124	31980	31094	32625	31270	32809	31455
11. RESERVES AFTER MAINTENANCE (10-2)	6579	7457	6099	6578	5843	6736	5639	6025	4879	5287
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	26.9	32.8	24.1	27.9	22.4	27.7	20.9	23.9	17.5	20.2
13. FULL FORCED OUTAGES /1/	1643	2173	1645	2185	1676	2255	1711	2268	1722	2282
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	29395	28041	29710	27939	30304	28839	30914	29002	31087	29173
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	4936	5284	4454	4393	4167	4481	3928	3757	3157	3005
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	20.2	23.2	17.6	18.6	15.9	18.4	14.6	14.9	11.3	11.5
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	558	639	559	644	569	663	581	667	585	671
18. ACTUAL CAPABILITY (14-17)	28837	27402	29151	27295	29735	28176	30333	28335	30502	28502
19. ACTUAL RESERVES (18-2)	4378	4645	3895	3749	3598	3818	3347	3090	2572	2334
20. ACTUAL RESERVES (%) (19/2)X100	17.9	20.4	15.4	15.9	13.8	15.7	12.4	12.2	9.2	8.9

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

TABLE 5A.8 SHEET 1 OF 2

INSTALLED NET SUMMER CAPABILITY BY TYPE, AS OF MAY 31 - MW

MID-CONTINENT AREA POWER POOL (REGION 20)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	3706	15085	577	2932	271	213	72	34	3006	0	25896
% TOTAL	14.3	58.4	2.2	11.3	1.0	0.8	0.3	0.1	11.6	0.0	100.0
SUMMER 1981	3720	16315	577	2932	284	213	72	27	3000	0	27140
% TOTAL	13.7	60.2	2.1	10.8	1.0	0.8	0.3	0.1	11.0	0.0	100.0
SUMMER 1982	3720	16860	577	2981	264	213	72	27	2953	0	27667
% TOTAL	13.4	60.8	2.1	10.8	1.0	0.8	0.3	0.1	10.7	0.0	100.0
SUMMER 1983	3720	17560	577	2958	245	213	72	27	2933	0	28305
% TOTAL	13.1	62.1	2.0	10.4	0.9	0.8	0.3	0.1	10.3	0.0	100.0
SUMMER 1984	3720	18759	577	2958	243	213	72	27	2964	0	29533
% TOTAL	12.6	63.7	1.9	10.0	0.8	0.7	0.2	0.1	10.0	0.0	100.0
SUMMER 1985	3720	19210	577	2958	243	213	72	27	2961	0	29981
% TOTAL	12.4	64.1	1.9	9.5	0.8	0.7	0.2	0.1	9.9	0.0	100.0
SUMMER 1986	3720	20275	577	2958	243	213	72	27	2949	0	31034
% TOTAL	12.0	65.3	1.9	9.5	0.8	0.7	0.2	0.1	9.5	0.0	100.0
SUMMER 1987	3720	20400	577	2958	243	213	72	27	2854	0	31064
% TOTAL	12.0	65.6	1.9	9.5	0.8	0.7	0.2	0.1	9.2	0.0	100.0
SUMMER 1988	3720	20979	564	2958	234	213	72	27	2884	0	31651
% TOTAL	11.7	66.4	1.8	9.3	0.7	0.7	0.2	0.1	9.1	0.0	100.0
SUMMER 1989	3720	21654	564	2958	234	213	72	27	2884	0	32326
% TOTAL	11.5	67.1	1.7	9.1	0.7	0.7	0.2	0.1	8.9	0.0	100.0
SUMMER 1990	3720	21854	564	2958	234	213	72	27	2876	0	32518
% TOTAL	11.4	67.3	1.7	9.1	0.7	0.7	0.2	0.1	8.8	0.0	100.0

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TABLE 5A.8

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INSTALLED NET WINTER CAPABILITY BY TYPE OF FUEL, AS OF NOV.30 - MW

MID-CONTINENT AREA POWER POOL (REGION 20)

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL CT	OIL IC	NAT.GAS STEAM	NAT.GAS CT	NAT.GAS IC	HYDRO CONV.	HYDRO PS	TOTAL CAP.
JAN. 1981	3796	15112	564	3727	273	202	95	34	2913	0	26716
% TOTAL	14.2	56.6	2.1	13.9	1.0	0.8	0.4	0.1	10.9	0.0	100.0
WINTER 1981	3815	17514	564	3727	265	202	95	27	3076	0	29285
% TOTAL	13.0	59.9	1.9	12.7	0.9	0.7	0.3	0.1	10.5	0.0	100.0
WINTER 1982	3815	17607	564	3757	246	202	95	27	3043	0	29356
% TOTAL	13.0	60.1	1.9	12.8	0.8	0.7	0.3	0.1	10.3	0.0	100.0
WINTER 1983	3815	18806	564	3757	242	202	95	27	3038	0	30546
% TOTAL	12.5	61.6	1.8	12.3	0.8	0.7	0.3	0.1	9.9	0.0	100.0
WINTER 1984	3815	18805	564	3757	242	202	95	27	3067	0	30574
% TOTAL	12.5	61.5	1.8	12.3	0.8	0.7	0.3	0.1	10.0	0.0	100.0
WINTER 1985	3815	19671	564	3757	242	202	95	27	3063	0	31436
% TOTAL	12.1	62.7	1.8	11.9	0.8	0.6	0.3	0.1	9.7	0.0	100.0
WINTER 1986	3815	20428	564	3757	242	202	95	27	3055	0	32185
% TOTAL	11.8	63.7	1.7	11.6	0.7	0.6	0.3	0.1	9.5	0.0	100.0
WINTER 1987	3815	20747	551	3757	233	202	95	27	2988	0	32415
% TOTAL	11.7	64.1	1.7	11.6	0.7	0.6	0.3	0.1	9.2	0.0	100.0
WINTER 1988	3815	21681	551	3757	233	202	95	27	3018	0	33379
% TOTAL	11.4	65.1	1.6	11.2	0.7	0.6	0.3	0.1	9.0	0.0	100.0
WINTER 1989	3815	21880	551	3757	233	202	95	27	3018	0	33578
% TOTAL	11.3	65.2	1.6	11.2	0.7	0.6	0.3	0.1	9.0	0.0	100.0
WINTER 1990	3815	22105	551	3757	216	202	95	27	3020	0	33788
% TOTAL	11.3	65.5	1.6	11.1	0.6	0.6	0.3	0.1	8.9	0.0	100.0

Sheet 1 of 2

TABLE 5A.9
MAJOR FUTURE GENERATING CAPABILITY INSTALLATIONS (AND REMOVALS)

MAPP REGION

Operating System	Station	Unit Type	Fuel Type	Net Capability-MW		In-Service Date	
				Summer	Winter	4/1/80 Report	4/1/81 Report
ISU*	Ottumwa	ST	SUB	675	675	12/31/80	4/1/81
OTP*	Coyote	ST	LIG	410	410	5/1/81	5/1/81
BEPC*	Laramie River #2	ST	SUB	550	550	4/1/81	6/4/81
NPPD	Gentleman 2	ST	SUB	600	600	11/1/81	11/1/81
	Total 1981			2235	2235		
BEPC**	Laramie River 2	ST	SUB	(550)	(550)	-	5/1/82
MBMPA*	Laramie River 3	ST	SUB	550	550	-	11/1/82
MPW	Muscatine 9	ST	BIT	150	150	5/1/82	11/1/82
	Total 1982			150	150		
BEPC	Antelope Valley 1	ST	LIG	416	416	4/15/82	7/1/83
IIGE*	Louisa	ST	SUB	650	650	7/1/83	7/1/83
	Total 1983			1066	1066		
NSP*	Sherburne Co. 3	ST	SUB	800	800	5/1/85	5/1/85
BEPC	Antelope Valley 2	ST	LIG	416	416	11/1/83	11/1/85
IELP*	Guthrie Co.	ST	BIT	650	650	12/31/84	12/31/85
	Total 1985			1866	1866		
OTP	Spiritwood	ST	LIG	125	125	11/1/85	11/1/86
DPC	Project 87	ST	SUB	400	400	11/1/87	11/1/87

* Units jointly owned by two or more systems. See Table 5A.10 for identify of owners and relative shares of ownership.

** Output of Laramie River Plant utilized in both the MARCA and WSCC regions. In May, 1982, output of Laramie River No. 2 unit is to be marketed in WSCC region.

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TABLE 5A.9
MAJOR FUTURE GENERATING CAPABILITY INSTALLATIONS (AND REMOVALS)

MAPP REGION

Operating System	Station	Unit Type	Fuel Type	Net Capability-MW Summer	Net Capability-MW Winter	In-Service Date 4/1/80 Report	In-Service Date 4/1/81 Report
IPS*	Neal 5	ST	SUB	400	400	5/1/87	5/1/88
BEPC	Antelope Valley 3	ST	LIG	400	400	4/1/87	11/1/88
MPL*	Oliver Co. 1	ST	LIG	500	500	11/1/88	11/1/88
	Total 1988			1300	1300		
IPS*	Allied	ST	BIT	400	400	5/1/85	11/1/89
MPL*	Oliver Co. 2	ST	LIG	500	500	-	11/1/90

* Units jointly owned by two or more systems. See Table 5A.10 for identity of owners and relative shares of ownership.

Sheet 1 of 2

TABLE 5A.10

JOINT OWNERSHIP OF FUTURE UNITS
MAPP REGION

UNIT NAME	UNIT NO	SHARING SYSTEMS	SUMMER MW SHARE	PERCENT SHARE
Allied	1	IPS (CBPC)	100.00	25.00
		EILP	50.00	12.50
		NIPC	50.00	12.50
		UNDET	200.00	50.00
Effective 11/01/89			400.00	100.00
Coyote	1	OTP	143.50	35.00
		MPC	123.00	30.00
		MDU	82.00	20.00
		NWPS	41.00	10.00
		MPL	20.50	5.00
Effective 05/01/81			410.00	100.00
Guthrie County	1	IELP (CIPC)	400.00	61.54
		ISP	150.00	23.08
		IPL	100.00	15.38
Effective 12/31/85			650.00	100.00
Laramie River	2	BEPC	191.00	34.73
		MBMP	181.00	32.91
		LES	147.00	26.73
		HCPD	31.00	5.63
Effective 06/01/81			550.00	100.00
		BEPC	0.00	0.00
		MBMP	0.00	0.00
		LES	0.00	0.00
		HCPD	0.00	0.00
Effective 05/01/81			0.00	0.00
Laramie River	3	BEPC	154.00	28.00
		MBMP	197.00	35.82
		LES	153.00	27.82
		HCPD	46.00	8.36
Effective 11/01/82			550.00	100.00
Louisa	1	IIGE	300.00	46.20
		IPL	211.00	32.40
		IPS	100.00	15.48
		EILP	30.00	4.60
		MUNIS	9.00	1.40
Effective 07/01/83			600.00	100.00
Neal	5	IPS	200.00	50.00
		UNDET	200.00	50.00
Effective 05/01/88			400.00	100.00
Oliver County	1	MPL	275.00	55.00
		UNDET	225.00	45.00
Effective 11/01/88			500.00	100.00
Oliver County	2	MPL	225.00	45.00
		UNDET	275.00	55.00
Effective 11/01/90			500.00	100.00
Ottumwa	1	ISU	223.00	33.00
		IIGE	125.00	18.50
		IPS	125.00	18.50
		IPL	101.00	15.00
		IELP	101.00	15.00
Effective 04/01/81			675.00	100.00
Project 87	1	DPC	320.00	80.00
		UNDET	80.00	20.00
Effective 11/01/87			400.00	100.00
Sherburne Co.	3	NSP	431.00	53.87
		LSDP	20.00	2.50
		SMMPA	300.00	37.50
		UMMPA	49.00	6.13
Effective 05/01/85			800.00	100.00

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TABLE 5A.10

JOINT OWNERSHIP OF FUTURE UNITS
MAPP REGION

UNIT NAME	NO	SHARING SYSTEMS	SUMMER MW SHARE	PERCENT SHARE	UNIT NAME	NO	SHARING SYSTEMS	SUMMER MW SHARE	PERCENT SHARE
		BEPC	12.00	2.18					
		MBMP	272.00	49.46					
		LES	220.00	40.00					
		HCPD	46.00	8.36					
Effective 6/01/83			550.00	100.00					

SECTION XIV.6
NORTHEAST POWER COORDINATING COUNCIL
(NPCC)

NORTHEAST POWER COORDINATING COUNCIL

Introduction

The Northeast Power Coordinating Council (NPCC) includes twenty-one utility system members located in the six New England states, New York, Ontario and New Brunswick. There are four operating entities or subregions -- two in the United States, and two in Canada. This report primarily addresses the United States' portion of the Council, a relatively small area geographically. It has a high population density and accounts for about 9 percent of the total generation in the contiguous United States.

The U.S. portions of the NPCC are heavily dependent on oil (the majority of which is is imported) as a boiler fuel, and approximately one-half of all the electric energy produced in the region was supplied by oil-fired generation. As such, it is the largest oil consumer of all the regions in NERC.

Of the two subregions in the U.S., the New England Power Pool (NEPOOL) is a winter peaking system, while the New York Power Pool (NYPP) is a summer peaking system. However, there is a little inter-pool diversity. Each pool takes advantage of intra-system diversity in establishing reserve criteria. The New York Power Pool is unique in that it is the only Electric Region integrated operating region which covers all of a single state.

Table 6.1 presents the current year's summer picture of transfer capabilities for the NPCC Region, while Table 6.2 provides planned capacity exchanges. NPCC has scheduled almost 1000 MW of firm receipts from Canada for the forecast period with approximately 80 percent import from Hydro Quebec.

Table 6.1

Intra-Regional First Contingency Incremental Transfer Capability

Northeast Power Coordinating Council

	1981 Summer (MW)
New York - New England	1,313
New England - New York	1,637
New York - Ontario Hydro	1,675
Ontario Hydro - New York	1,725
New England - New Brunswick	433
New Brunswick - New England	467

TABLE 6.2

PLANNED CAPACITY EXCHANGES

NORTHEAST POWER COORDINATING COUNCIL

	1982		1983		1984		1985		1990	
IMPORTS	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
HYDRO QUEBEC	800.0	0	800.0	0	800.0	0	800.0	0	800.0	0
METRO DISTRICT	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
N.E. INDUSTRIALS	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
NEW BRUNSWICK	133.0	133.0	133.0	133.0	133.0	133.0	133.0	0	0	0
SO. CANADA	37.0	0	39.0	0	42.0	0	46.0	0	0	0
ONTARIO HYDRO	11.8	11.8	11.8	11.8	11.8	0	0	0	0	0
NBEPCO	31.0	31.0	31.0	30.0	30.0	30.0	30.0	30.0	29.0	29.0
EXPORTS										
PUBLIC SERVICE BD. OF VERMONT	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
AMP OHIO	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
ALLEGHENY ELEC. COOP (GPU)	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0	107.0

BASED ON ERA FORM 411

A. ELECTRIC REGION 3 - NEW ENGLAND POWER POOL

Historical Perspective

NEPOOL is the coordinating pool for the six New England states and includes over forty privately and publicly-owned utilities operating in the six New England states. There are two functional components of NEPOOL: NEPLAN, the planning organization; and NEPEX, the operating section. As a result of its geography, the region is almost totally dependent on expensive imported oil to meet fossil fuel requirements. Thus, most major capacity additions have been planned for nuclear power.

Growth in the Electric Region since 1977 has been very small. Table 6A.1 indicates that in these years the average annual winter peak growth has been less than 2 percent and energy growth about 2 percent. This in part can be explained by mild weather and the increasing costs of electric power.

TABLE 6A.1

ACTUAL ANNUAL NET ENERGY, PEAK DEMANDS, AND LOAD FACTORS

NEW ENGLAND POWER POOL

	NET ENERGY		SUMMER PEAK		WINTER PEAK		
YEAR	G W H	PERCENT CHANGE	M W	PERCENT CHANGE	M W	PERCENT CHANGE	LOAD FACTOR
1977	79,734	-	14,194	-	14,822	-	61
1978	82,505	3.5	14,404	1.5	15,072	1.7	62
1979	83,958	1.8	14,324	(0.6)	15,278	1.4	63
1980	85,050	1.3	14,986	4.6	15,610	2.2	62

BASED ON ERA-411 FORM

[redacted]

A breakdown of the actual 1979/1980 winter capability by prime mover and fuel type is shown below.

Table 6A.2

1979/80 Net Dependable Winter Capability By Prime Mover and Fuel Type *

New England Power Pool

Prime Mover	Type	MW	% Total
Steam	Nuclear	4,314	20.9
Steam	Coal	456	2.1
Steam	Oil	11,819	54.1
Steam	Gas	0	0
Hydro	-	1,300	6.6
Pumped Storage	-	1,633	7.5
Gas Turbine	Oil	1,717	7.9
Gas Turbine	Gas	0	0
Combined Cycle	Oil	206	0.9
Combined Cycle	Gas	0	0
Total		21,445	100.0

* 1980 NERC Summary of Peak Load and Capability

Table 6A.3 gives a breakdown of NEPOOL's generation output and capability by fuel type over the 1977 to 1980 period. Oil has provided almost 60 percent of NEPOOL generation while nuclear has provided approximately one third. In terms of total generating capability, oil has provided close to 65 percent while nuclear has provided 20 percent. For the purpose of these comparisons, the pumped storage figures have been deleted.

TABLE 6A.3

ACTUAL 1977-1980 GENERATION BY FUEL TYPE

AND ACTUAL 1979-1980 CAPABILITY BY FUEL TYPE

NEW ENGLAND POWER POOL

NEPOOL GENERATION
PERCENTAGE OF TOTAL

YEAR	NUCLEAR	HYDRO	COAL	OIL	GAS
1977	33	7	3	57	0
1978	35	5	3	57	0
1979	34	6	5	55	1
1980	32	4	5	59	0

PLANT CAPABILITY
PERCENTAGE OF TOTAL

YEAR	NUCLEAR	HYDRO	COAL	OIL	GAS
1979	20.1	13.6	2.1	64.1	0.1
1980	20.1	13.6	2.1	64.1	0.1

BASED ON ERA FORM 411

The New England companies anticipated the present fuel supply situation many years ago and thus committed the Electric Region to nuclear power. The region has six nuclear units operational. As early as 1978, the region included nine percent of the total nuclear capacity of the United States. This translates into 20 percent of New England capacity and thirty-five percent of the region's generation output for that year.

The total nuclear generation for 1979 was slightly below that of 1978 due to several outages including a prolonged outage of the Maine Yankee Plant. The total plant output for the region was also reduced as a result of increased purchases from coal-burning utilities in the West. This transfer of energy helped to reduce the amount of oil generation even though there was a reduction in nuclear plant output. The 1980 nuclear generation shows a continued decrease in percentage as nuclear outages continue to accommodate modifications required by NRC as a result of the Three Mile Island accident. Such nuclear unit outages will not adversely affect system reliability.

Table 6A.9 shows that from 1977 to 1980 minimum planned capacity reserves as a percent of the peak load varied between 35 percent and 40 percent for the winter and peaked at 44 percent in the summer. These reserves compare favorably with the planned reserve criteria of 23 percent to 24 percent, established by the NEPOOL Agreement. If net sales and purchases and unavailable capacity over the peak were considered, the reserves would be reduced to as low as zero in the summer and 11 percent in the winter. As a result of intra-pool diversity, the individual company reserves can be as low as 18 percent and still meet the overall pool criteria. The planned reserves are the results of forecast decisions made in 1975, when load growth was 7.5 percent.

[redacted]

Since then, there have been large reductions in forecasted load growth due to economic changes and the demand restraint after-effects of the oil embargo.

In general, the reserve margin criterion is a function of the mix and maturity of the net dependable capacity and the load. With the recent increases in system load factor this value has had to increase as there is less off-peak excess capacity available for planned maintenance. Also, since the inter-regional ties to the North are rated at low capacity, the area is assumed to be a peninsular system and this requires higher reserves than a region with interconnections on several sides.

Consequently, NEPOOL has transmission ties equal to about 4 percent of installed capacity as compared to NYPP where the interconnection ties equal about 10 percent of installed capacity.

The NEPOOL Agreement states that operating reserves, equal to one and one-half times the capacity of the largest unit on the line, must be maintained. Of this, one-half of the capacity must be available in 30 minutes. Capacity equal to the largest possible system contingency must be available in 10 minutes with one-third of that capacity synchronized. Additional load relief of 2 percent is available with a 5 percent voltage reduction; and generally, public appeals result in another one and one-half percent of load reduction. Table 6A.4 shows that six NEPOOL companies have interruptible load contracts providing an additional 57 MW of capacity during emergencies.

Table 6A.4

Interruptible Load Contracts

NEPOOL

Utility	Interruptible Load - MW	Contractual Conditions
BAHE (C)	16	Load reduction upon 10 minutes notice. (B)
BAHE	10	Load reduction upon 30 minutes notice. (B)
BOEC	6	Load reduction upon 10 minutes notice. (B)
NEGE	8	Load reduction upon 10 minutes notice. (A)
PSNH	13	Load reduction upon 10 minutes notice. (A)
VTGP	4	Load reduction upon 10 minutes notice. (A)

(A) - No limit to hours, MW, or energy interrupted.
(B) - Limited as to hours, MW, or energy which may be interrupted.
(C) - BAHE - Bangor Hydro Electric Co., BOEC - Boston Edison Co, NEGE - New England Gas and Electric Association, PSNH - Public Service Co. of New Hampshire, VTGP - Vermont Group

Based on Form ERA-411.

The transmission system includes 444 miles of 230 KV lines and 1,552 miles of 345 KV lines. The transmission is adequate for handling the area loads and energy transfers with reserve for economy and oil conservation transactions. All transmission system constraints are thermal rather than stability limited.

With rising fuel oil prices, home heating with electricity is becoming more attractive in the area even though the cost of electric power is increasing. In an area with a winter peak, this situation is less than ideal for the power companies and, as such, some form of load management is becoming important. Several companies in the area have timers on water heaters to reduce peak loads, and experimental systems with ripple control have been installed. Additionally, some companies have seasonal rates. The companies are also assisting their customers in the use of heat storage systems for home heating rather than baseboard or similar types of heating systems. With the area's prevailing cool summer temperatures, there is a lack of need for air-conditioning, contributing to heat pumps' not being economically viable.

[redacted]

Current Perspective

NEPOOL is a winter peaking region, though some systems in Connecticut have a summer peak. The anticipated winter 1981-82 peak for the NEPOOL System is 15,920 MW and is expected to occur in January 1982, marking an increase of 1.9 percent over the 1980-81 winter peak. This estimate represents a decrease in estimated growth as compared to the previous forecast for this period. Total net energy for 1981 is anticipated at 87,360 GWH, representing a 2.7 percent growth over 1980 -- a somewhat larger increase than was experienced in the previous year. The anticipated 1981 annual load factor is 63 percent. The planned capability and resultant reserve margins estimated to meet the 1981/82 winter peak are shown in Table 6A.5.

TABLE 6A.5

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW ENGLAND POWER POOL

	1981 SUMMER	1981 WINTER
1. PLANNED CAPABILITY (MW)	20644	21724
2. PEAK DEMAND (MW)	14780	15920
3. PLANNED RESERVES (MW)(1-2)	5864	5804
4. PLANNED RESERVES (%) (3/2) X 100	39.7	36.5
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	362	188
6. TOTAL CAPABILITY (MW) (1+5)	21006	21912
7. TOTAL RESERVES (MW) (6-2)	6226	5992
8. TOTAL RESERVES (%) (7/2) X 100	42.1	37.6
9. SCHEDULED MAINTENANCE (MW)	1652	565
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	19354	21347
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	4574	5427
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	30.9	34.1
13. FULL FORCED OUTAGES (MW)	1775	2172
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	17579	19175
15. AVAILABLE RESERVES (MW) (14-2)	2799	3255
16. AVAILABLE RESERVES (%) (15/2) X 100	18.9	20.4
17. OTHER UNAVAILABLE CAPABILITY (MW)	1507	976
18. AVAILABLE CAPABILITY (MW) (14-17)	16072	18199
19. ACTUAL RESERVES (MW) (18-2)	1292	2279
20. ACTUAL RESERVES (%) (19/2) X 100	8.7	14.3
EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION		
21. NUCLEAR DELAYS (MW)	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	16072	18199
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	1292	2279
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	8.7	14.3

Two major transmission lines are expected to be in service prior to the summer peak: the Seabrook-Newington 345 KV line (18.5 miles) and the Bloomfield-Meekville Junction 345 KV line (14.0 miles). The first line is required to provide transmission capability to deliver output of new generation to the transmission grid, and the second line is needed to supply increased load. The transmission system is adequate to cover load commitments for the year with no stability problem areas. Transmission additions scheduled for 1981 include 22.5 miles of 115 and 138 KV and 37 miles of 345 KV.

[redacted]

Future Perspective

The 1981 through 1990 period forecasts show an average winter peak growth of 2.8 percent per year. From 1981 to 1984 the expected growth rate is 2.5 percent and the rate from 1986 to 1990 is 2.9 percent per year. The summer average peak growth for the 1981 through 1990 period is 2.5 percent, and the average energy growth during the same period is anticipated to be 2.8 percent. Table 6A.6 shows projected annual energy and peak demands and indicates the annual growths in percent. Tables 6A.10.1, 6A.10.2, and 6A.10.3 show projected reserve margins for the 1982-1990 period.

TABLE 6A.6

PROJECTED ENERGY AND PEAK DEMAND

NEW ENGLAND POWER POOL

YEAR	ENERGY REQUIREMENTS		SUMMER PEAK DEMAND		WINTER PEAK DEMAND		ANNUAL LOAD FACTOR
	GWH	PERCENT GROWTH	MW	PERCENT GROWTH	MW	PERCENT GROWTH	PERCENT
1981	87,360	2.7	14,780	(1.4)	15,920	2.0	62.6
1982	89,837	2.8	15,170	2.6	16,350	2.7	62.7
1983	92,[illegible]11	2.9	15,550	2.5	16,810	2.8	62.8
1984	94,961	2.8	15,920	2.4	17,260	2.7	62.6
1985	97,307	2.5	16,250	2.1	17,680	2.4	62.8
GROWTH 81-85		2.7		2.4		2.5	
1986	99,800	2.6	16,620	2.3	18,130	2.5	62.8
1987	102,550	2.8	17,020	2.4	18,640	2.8	62.8
1988	105,506	2.9	17,460	2.6	19,200	3.0	62.7
1989	108,654	3.0	17,940	2.7	19,780	3.0	62.7
1990	111,893	3.0	18,430	2.7	20,360	2.9	62.7
GROWTH 86-90		2.9		2.6		2.9	
GROWTH 81-90		2.8		2.5		2.8	

While these capacity reserve margins exceed the NEPOOL Agreement criteria, they are based on a very moderate load growth estimate and timely completion of capacity planned and under construction.

To meet the projected load growth, approximately 5,450 MW of new base load generating capacity additions is planned. This will include 4,600 MW of nuclear, 568 MW of coal-fired, and 279 MW of oil capacity. Tables 6A.11.1 and 6A.11.2 show projections of capacity mix for the years 1982 through 1990 at the time of the summer and winter peaks.

The estimated power output for 1985 is 92,560 GWH, and the forecasted fuel requirements to meet this generation are 4.2 million tons of coal, 66.6 million barrels of residual oil, and 3.2 million barrels of distillate oil. The corresponding requirements to meet the 1989 generation of 106,437 GWH are 4.6 million tons of coal, 62.3 million barrels of residual oil, and 2.3 million barrels of distillate oil. These figures show some reduction in regional dependence on imported oil.

Table 6A.7 identifies the major nuclear and coal units planned and under construction for the region. The table also shows the historical slippage experienced for each of the planned units.

TABLE 6A.7

MAJOR FUTURE GENERATING UNIT IN-SERVICE DATES

NEW ENGLAND POWER POOL

UTILITY	PLANT NAME	NAME PLATE CAPACITY (MW)	ORIGINAL IN-SERVICE DATE	IN-SERVICE DATE AS OF APRIL 1980	PRESENT IN-SERVICE DATE
		NUCLEAR			
PSNH	SEABROOK #1	1150	NOV 1979	APR 1983	APR 1983
PSNH	SEABROOK #2	1150	NOV 1981	FEB 1985	FEB 1985
NOEN	MILLSTONE #3	1150	MAY 1979	MAY 1986	MAY 1986
BOEC	PILGRIM #2	1150	NOV 1978	DEC 1985	NOV 1987
		COAL			
CEMP	SEARS ISLAND	568	NOV 1983	NOV 1987	MAY 1989
		OIL			
MMWE	STONY BROOK	279	NOV 1981	NOV 1981	NOV 1981

BASED ON ERA FORM 411

A critical transmission addition for the period continues to be the West Walpole - Needham 345 KV line, located in the Boston area. Completion of this line has been delayed two years due to regulatory hearings and approvals. The delay will impact the reliability of the transmission system supplying the Boston area in that satisfactory system voltages may not be maintained during heavy load conditions, and multiple contingencies could result in loss of load in the Boston area.

[redacted]

Planned, under construction, or committed transmission lines for the future are presented in Table 6A.8.

Table 6A.8

Planned, Under Construction, or Committed Transmission Lines
New England Power Pool

Year	Voltage (KV)	Miles
1981-1985	138/115	242.7
1986-1990	138/115	156.5
Total	138/115	399.2
1981-1985	230	0.4
1986-1990	230	0.0
Total	230	0.4
1981-1985	345	206.8
1986-1990	345	367.7
Total	345	574.5
1981-1985	500	0.0
1986-1990	500	0.0
Total	500	0.0

Based on Form ERA-411.

TABLE 6A.9

HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW ENGLAND POWER POOL

	1977		1978		1979		1980	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	20075	20790	19921	21198	20550	21168	20404	21120
2. PEAK DEMAND (MW)	14194	14822	14404	15072	14324	15278	14986	15610
3. PLANNED RESERVES (MW)(1-2)	5881	5968	5517	6126	6226	5890	5418	5510
4. PLANNED RESERVES (%) (3/2) X 100	41.4	40.3	38.3	40.6	43.5	38.6	36.2	35.3
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	164	162	162	163	150	150	350	567
6. TOTAL CAPABILITY (MW) (1+5)	20239	20952	20083	21361	20700	21318	20754	21687
7. TOTAL RESERVES (MW) (6-2)	6045	6130	5679	6289	6376	6040	5768	6077
8. TOTAL RESERVES (%) (7/2) X 100	42.6	41.4	39.4	41.7	44.5	39.5	38.5	38.9
9. SCHEDULED MAINTENANCE (MW)	0	0	0	0	0	0	1402	1780
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	20239	20952	20083	21361	20700	21318	19352	19907
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	6045	6130	5679	6289	6376	6040	4366	4297
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	42.6	41.4	39.4	41.7	44.5	39.5	29.1	27.5
13. FULL FORCED OUTAGES (MW)	0	0	0	0	0	0	1748	1233
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	20239	20952	20083	21361	20700	21318	17604	18674
15. AVAILABLE RESERVES (MW) (14-2)	6045	6130	5679	6289	6376	6040	2618	3064
16. AVAILABLE RESERVES (%) (15/2) X 100	42.6	41.4	39.4	41.7	44.5	39.5	17.5	19.6
17. OTHER UNAVAILABLE CAPABILITY (MW)	5043	4322	5775	4366	4841	4332	1323	1412
18. AVAILABLE CAPABILITY (MW) (14-17)	15196	16630	14308	16995	15859	16986	16281	17262
19. ACTUAL RESERVES (MW) (18-2)	1002	1808	-96	1923	1535	1708	1295	1652
20. ACTUAL RESERVES (%) (19/2) X 100	7.1	12.2	-0.7	12.8	10.7	11.2	8.6	10.6

TABLE 6A.10.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW ENGLAND POWER POOL

	1982		1983		1984	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	20946	21864	22204	23032	22207	23024
2. PEAK DEMAND (MW)	15170	16350	15550	16810	15920	17260
3. PLANNED RESERVES (MW)(1-2)	5776	5514	6654	6222	6287	5764
4. PLANNED RESERVES (%) (3/2) X 100	38.1	33.7	42.8	37.0	39.5	33.4
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	367	330	369	329	371	318
6. TOTAL CAPABILITY (MW) (1+5)	21313	22194	22573	23361	22578	23342
7. TOTAL RESERVES (MW) (6-2)	6143	5844	7023	6551	6658	6082
8. TOTAL RESERVES (%) (7/2) X 100	40.5	35.7	45.2	39.0	41.8	35.2
9. SCHEDULED MAINTENANCE (MW)	1697	568	1799	599	1799	599
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	19616	21626	20774	22762	20779	22743
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	4446	5276	5224	5952	4859	5483
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	29.3	32.3	33.6	35.4	30.5	31.8
13. FULL FORCED OUTAGES (MW)	1780	2186	1887	2303	1888	2302
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	17836	19440	18887	20459	18891	20441
15. AVAILABLE RESERVES (MW) (14-2)	2666	3090	3337	3649	2971	3181
16. AVAILABLE RESERVES (%) (15/2) X 100	17.6	18.9	21.5	21.7	18.7	18.4
17. OTHER UNAVAILABLE CAPABILITY (MW)	1529	984	1621	1036	1621	1036
18. AVAILABLE CAPABILITY (MW) (14-17)	16307	18456	17266	19423	17270	19405
19. ACTUAL RESERVES (MW) (18-2)	1137	2106	1716	2613	1350	2145
20. ACTUAL RESERVES (%) (19/2) X 100	7.5	12.9	11.0	15.5	8.5	12.4

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	0	0	1150	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	16307	18456	16116	19423	17270	19405
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	1137	2106	566	2613	1350	2145
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	7.5	12.9	3.6	15.5	8.5	12.4

TABLE 6A.10.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW ENGLAND POWER POOL

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	23359	24185	24511	25337	24512	26357
2. PEAK DEMAND (MW)	16250	17680	16620	18130	17020	18640
3. PLANNED RESERVES (MW)(1-2)	7109	6505	7891	7207	7492	7717
4. PLANNED RESERVES (%) (3/2) X 100	43.7	36.8	47.5	39.8	44.0	41.4
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	362	183	183	183	183	182
6. TOTAL CAPABILITY (MW) (1+5)	23721	24368	24694	25520	24695	26539
7. TOTAL RESERVES (MW) (6-2)	7471	6688	8074	7390	7675	7899
8. TOTAL RESERVES (%) (7/2) X 100	46.0	37.8	48.6	40.8	45.1	42.4
9. SCHEDULED MAINTENANCE (MW)	1892	629	1985	659	1985	685
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	21829	23739	22709	24861	22710	25854
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	5579	6059	6089	6731	5690	7214
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	34.3	34.3	36.6	37.1	33.4	38.7
13. FULL FORCED OUTAGES (MW)	1986	2419	2083	2534	2084	2636
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	19843	21320	20626	22327	20626	23218
15. AVAILABLE RESERVES (MW) (14-2)	3593	3640	4006	4197	3606	4578
16. AVAILABLE RESERVES (%) (15/2) X 100	22.1	20.6	24.1	23.1	21.2	24.6
17. OTHER UNAVAILABLE CAPABILITY (MW)	1705	1088	1789	1140	1789	1186
18. AVAILABLE CAPABILITY (MW) (14-17)	18138	20232	18837	21187	18837	22032
19. ACTUAL RESERVES (MW) (18-2)	1888	2552	2217	3057	1817	3392
20. ACTUAL RESERVES (%) (19/2) X 100	11.6	14.4	13.3	16.9	10.7	18.2

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. NUCLEAR DELAYS (MW)	0	1150	1150	0	0	1150
22. ACTUAL CAPABILITY (MW) (18-21)	18138	19082	17687	21187	18837	20882
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	1888	1402	1067	3057	1817	2242
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	11.6	7.9	6.4	16.9	10.7	12.0

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TABLE 6A.10.3

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW ENGLAND POWER POOL

	1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	25537	26357	25537	26924	26104	26926
2. PEAK DEMAND (MW)	17460	19200	17940	19780	18430	20360
3. PLANNED RESERVES (MW)(1-2)	8077	7157	7597	7144	7674	6566
4. PLANNED RESERVES (%) (3/2) X 100	46.3	37.3	42.3	36.1	41.6	32.2
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	182	182	182	182	182	182
6. TOTAL CAPABILITY (MW) (1+5)	25719	26539	25719	27106	26286	27108
7. TOTAL RESERVES (MW) (6-2)	8259	7339	7779	7326	7856	6748
8. TOTAL RESERVES (%) (7/2) X 100	47.3	38.2	43.4	37.0	42.6	33.1
9. SCHEDULED MAINTENANCE (MW)	2068	685	2068	700	2114	700
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	23651	25854	23651	26406	24172	26408
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	6191	6654	5711	6626	5742	6048
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	35.5	34.7	31.8	33.5	31.2	29.7
13. FULL FORCED OUTAGES (MW)	2171	2636	2171	2692	2219	2693
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	21480	23218	21480	23714	21953	23715
15. AVAILABLE RESERVES (MW) (14-2)	4020	4018	3540	3934	3523	3355
16. AVAILABLE RESERVES (%) (15/2) X 100	23.0	20.9	19.7	19.9	19.1	16.5
17. OTHER UNAVAILABLE CAPABILITY (MW)	1864	1186	1864	1212	1906	1212
18. AVAILABLE CAPABILITY (MW) (14-17)	19616	22032	19616	22502	20047	22503
19. ACTUAL RESERVES (MW) (18-2)	2156	2832	1676	2722	1617	2143
20. ACTUAL RESERVES (%) (19/2) X 100	12.3	14.7	9.3	13.8	8.8	10.5

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

	1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. NUCLEAR DELAYS (MW)	0	0	0	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	19616	22032	19616	22502	20047	22503
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	2156	2832	1676	2722	1617	2143
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	12.3	14.7	9.3	13.8	8.8	10.5

TABLE 6A.11.1

SUMMER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

NEW ENGLAND POWER POOL

YEAR	NUCLEAR STEAM	COAL STEAM	OIL			NATURAL GAS			HYDRO		TOTAL CAPABILITY
			STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	
1981	4228	455	11595	1196	262	27	0	0	1250	1631	20644
% TOTAL	20.5	4.6	53.7	5.8	1.3	0.1	0.0	0.0	6.1	7.9	100.0
1982	4228	1741	10291	1475	262	27	0	0	1291	1631	20946
% TOTAL	20.2	8.3	49.1	7.0	1.3	0.1	0.0	0.0	6.2	7.8	100.0
1983	5378	1741	10287	1605	228	27	0	0	1307	1631	22204
% TOTAL	24.2	7.8	46.3	7.2	1.0	0.1	0.0	0.0	6.0	7.3	100.0
1984	5378	1985	10043	1605	228	27	0	0	1310	1631	22207
% TOTAL	24.2	8.9	45.2	7.2	1.0	0.1	0.0	0.0	6.0	7.3	100.0
1985	6528	2566	9462	1599	228	27	0	0	1318	1631	23359
% TOTAL	27.9	11.0	40.6	6.8	1.0	0.1	0.0	0.0	5.6	7.0	100.0
1986	7678	3145	8883	1601	228	27	0	0	1318	1631	24511
% TOTAL	31.3	12.8	36.2	6.5	1.0	0.1	0.0	0.0	5.4	6.7	100.0
1987	7678	3145	8884	1601	228	27	0	0	1318	1631	24512
% TOTAL	31.3	12.8	36.2	6.5	1.0	0.1	0.0	0.0	5.4	6.7	100.0
1988	8828	3145	8760	1600	228	27	0	0	1318	1631	25537
% TOTAL	34.5	12.3	34.3	6.3	0.9	0.1	0.0	0.0	5.2	6.4	100.0
1988	8828	3145	8760	1600	228	27	0	0	1318	1631	25537
% TOTAL	34.5	12.3	34.3	6.3	0.9	0.1	0.0	0.0	5.2	6.4	100.0
1990	8828	3713	8760	1599	228	27	0	0	1318	1631	26104
% TOTAL	33.9	14.2	33.6	6.1	0.9	0.1	0.0	0.0	5.0	6.2	100.0

BASED ON ERA FORM 411

TABLE 6A.11.2

WINTER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

NEW ENGLAND POWER POOL

			OIL			NATURAL GAS			HYDRO		
YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	TOTAL CAPABILITY
1981	4338	977	11259	1929	263	27	0	0	1300	1631	21724
% TOTAL	20.0	4.5	51.8	8.9	1.2	0.1	0.0	0.0	6.0	7.5	100.0
1982	4338	1765	10464	2060	263	27	0	0	1316	1631	21864
% TOTAL	19.9	8.1	47.9	9.4	1.2	0.1	0.0	0.0	6.0	7.5	100.0
1983	5488	1917	10312	2060	263	27	0	0	1334	1631	23032
% TOTAL	23.8	8.3	44.8	9.0	1.1	0.1	0.0	0.0	5.8	7.1	100.0
1984	5488	2245	9983	2053	263	27	0	0	1334	1631	23024
% TOTAL	23.8	9.8	43.4	8.9	1.1	0.1	0.0	0.0	5.8	7.1	100.0
1985	6638	2769	9459	2055	263	27	0	0	1343	1631	24185
% TOTAL	27.5	11.4	39.1	8.5	1.1	0.1	0.0	0.0	5.6	6.7	100.0
1986	7788	3188	9042	2055	263	27	0	0	1343	1631	25337
% TOTAL	30.7	12.6	35.7	8.2	1.0	0.1	0.0	0.0	5.3	6.4	100.0
1987	8938	3188	8912	2055	263	27	0	0	1343	1631	26357
% TOTAL	33.9	12.1	33.8	7.8	1.0	0.1	0.0	0.0	5.1	6.2	100.0
1988	8938	3188	8912	2055	263	27	0	0	1343	1631	26357
% TOTAL	33.9	12.1	33.8	7.8	1.0	0.1	0.0	0.0	5.1	6.2	100.0
1989	8938	3756	8912	2054	263	27	0	0	1343	1631	26924
% TOTAL	33.2	13.9	33.1	7.6	1.0	0.1	0.0	0.0	5.0	6.1	100.0
1990	8938	3756	8912	2056	263	27	0	0	1343	1631	26926
% TOTAL	33.2	13.9	33.1	7.6	1.0	0.1	0.0	0.0	5.0	6.1	100.0

BASED ON ERA FORM 411

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B. ELECTRIC REGION 4 - NEW YORK POWER POOL

Historical Perspective

The New York Power Pool coordinates the planning and operation of the eight major electric utility companies in New York State. It is the only pool in the contiguous U.S. where the boundary of the electric region and the state coincide.

The New York Power Pool maintains an operating center near Albany, New York, for the electric utility companies. Included in this group is a state system--Power Authority of the State of New York (PASNY). The Power Authority has developed several large hydro-electric generating stations, including Niagara Falls. Additionally, it has built some of the major transmission lines in the state, including a 765 KV line that is used for heavy imports of Canadian hydro-electric power.

NYPP is the major importer of Canadian power for the eastern portion of the United States and provides a major transmission link for transporting power to New England from the coal-burning plants of the West, and hydro-electric power from Canada. The region's mix of generating capacity includes more than a third of imported oil-fired capacity with the remainder made up of small low-head hydro, nuclear, coal and gas by order of decreasing contribution.

Table 6B.1 presents a breakdown of the Pool's generation and capability by fuel type for the years 1977 through 1980.

TABLE 6B.1

ACTUAL 1977-1980 GENERATION BY FUEL TYPE

AND ACTUAL 1978-1980 CAPABILITY BY FUEL TYPE

NEW YORK POWER POOL

NYPP GENERATION
PERCENTAGE OF TOTAL

YEAR	NUCLEAR	HYDRO	COAL	OIL	GAS
1977	18	23	13	46	0
1978	19	23	12	46	0
1979	18	25	13	38	6
1980	17	24	17	32	10

PLANT CAPABILITY
PERCENTAGE OF TOTAL

YEAR	NUCLEAR	HYDRO	COAL	OIL	GAS
1978	12.4	14.1	12.3	61.1	0.1
1979	12.4	17.0	11.8	58.6	0.2
1980	11.9	16.6	11.6	59.8	0.1

BASED ON ERA FORM 411

[redacted]

Within the region, there has been a steady increase in the generation by coal and reduction in the generation by oil. Increased gas use and completion of a productivity improvement program on several large coal burning units in the state contributed to this trend. The coal-generating plants are located in the northern tier of the state, except for one jointly-owned plant, Homer City, located in Pennsylvania and owned by New York State Electric & Gas Co., and General Public Utilities in the MAAC area.

A comparison of net energy, peak demands and load factor for the period 1977 through 1980 is shown in Table 6B.2. The annual peak load and reserve margins are shown for the period 1977-1980 in Table 6B.9. Table 6B.2 shows net energy growth to have decreased from 1979 to 1980 relative to the 1978-79 period.

TABLE 6B.2

ACTUAL ANNUAL NET ENERGY, PEAK DEMANDS, AND LOAD FACTORS

NEW YORK POWER POOL

	NET ENERGY		SUMMER PEAK		WINTER PEAK		
YEAR	G W H	PERCENT CHANGE	M W	PERCENT CHANGE	M W	PERCENT CHANGE	LOAD FACTOR
1977	113,483	-	21,103	-	18,838	-	61
1978	114,860	1.2	20,316	(3.8)	19,598	4.0	65
1979	117,189	2.0	20,746	2.1	19,417	(1.0)	64
1980	118,866	1.4	21,740	4.5	19,865	2.3	62

BASED ON ERA-411 FORM

Minimum planned reserves ranged from 31 percent to 48 percent for the summer and from 44 percent to as high as 64 percent for the winter. After considering net interchange and unavailable capacity, these numbers were reduced to as low as 10 percent for the summer and 17 percent for the winter. Planned reserves were above the established pool planned reserve criteria of approximately 22 percent.

Plant capability, by fuel type, to meet the 1980 load requirements is presented in Table 6B.3.

Table 6B.3

1980 Net Dependable Capability By Prime Mover and Fuel Type
New York Power Pool

		Capability	
Prime Mover	Fuel Type	NW	Total
Steam	Nuclear	3,609	11.5
Steam	Coal	3,530	11.2
Steam	Oil	14,795	47.1
Steam	Gas		
Hydro		4,024	12.9
Pump Storage		1,000	3.2
Gas Turbine	Oil	4,379	13.9
Gas Turbine	Gas	30	0.1
Combine Cycle	Oil		
Combine Cycle	Gas		
Internal Combustion	Oil	62	0.1

[redacted]

Over fifteen percent of all of the residual oil used in the United States for electric generation is burned in the NYPP Region, and 30 percent of all residual is burned in the NPCC area where almost all of the oil used is imported.

During 1980, as in 1979, there was appreciable generation by gas; however, the future of this fuel for utility use is uncertain. At present FERC has granted a temporary exemption for its use.

NYPP planned reserves are large for the present. The design criteria call for a pool reserve of 22 percent. This requires that the individual members must provide 18 percent reserve over its annual peak. The lower reserve is permitted because of load diversity among the various members. With a company reserve of 18 percent, a 5 percent voltage reduction would result in a 4 percent reduction in peak, while customer appeals could shave the peak an additional 3 percent. In addition to the reserves, the Table 6B.4 shows three pool members to have interruptible customer contracts that permit a total load reduction of 172 MW.

Table 6B.4

Interruptible Load Contracts

NYPP

Utilities	Interruptible Load - MW	Contractual Conditions
COEN	15	Load reduction upon 30 minutes notice. Between 5/15 and 10/15, maximum number of interruptions 17, maximum duration 8 hours.
LOIL	2	Load reduction upon 18-hour notice. Temperature 90 degree or above, maximum number of interruptions 10 per year.
POAS	155	Aluminum company hot line.

Based on Form ERA-411.

Note: COEN - Consolidated Edison of New York Company
LOIL - Long Island Lighting Company
POAS - Power Authority of the State of New York

The transmission system includes 1,075 miles of 230 KV lines; 2,109 miles of 345 KV lines; 5 miles of 500 KV lines; and 155 miles of 765 KV lines. There are no stability constraints in the transmission system, and usually the thermal ratings of the lines control the limits of transfers which are frequently heavy from north to south.

Environmental constraints preclude the use of any fuel except low sulfur oil in the densely populated southern metropolitan area of the state. This, coupled with a New York City utility fuel use tax, makes it economically desirable to import as much energy into these regions as possible.

Additionally, several municipalities on Long Island are preferential customers of PASNY and, as such, are entitled to low cost hydro-electric energy which must be wheeled from upstate. Much of the imported Canadian hydro power also follows this route. This movement of energy creates two problems: First, in the area around Albany, close to the southern terminus of the Canadian - New York 765 KV line, there is heavy loading of the transmission system during off-peak periods when Canadian energy is being imported. This causes a backing off of the base loaded coal-fired plants which could normally be displacing oil capacity at this time. Second, in the transmission corridor between Albany and New York City, normal transmission loading is sufficiently high to preclude its use during prolonged outages of certain generating units; e.g. Indian Point. Any increase in Canadian hydro imports into this system could further aggravate this situation.

Current Perspective

The State of New York is a summer peaking region. Although the northern portion of the state has a winter peak, the larger loads of the downstate utilities swing the over-all state peak to summer. Table 6B. 5 estimates the 1981-82 winter peak to be 19,463 MW, a decrease of 2.0 percent from the previous year. Total net energy for 1981 is expected to reach 116,101 GWH, a decrease of 2.3 percent below the previous year. The annual load factor based on these forecasts would be 62.9 percent. The peak demands, capacity and reserve margins anticipated for 1981 are presented in Table 6B.6.

TABLE 6B.5

PROJECTED ENERGY AND PEAK DEMAND

NEW YORK POWER POOL

YEAR	ENERGY REQUIREMENTS		SUMMER PEAK DEMAND		WINTER PEAK DEMAND		ANNUAL LOAD FACTOR
	GWH	PERCENT GROWTH	MW	PERCENT GROWTH	MW	PERCENT GROWTH	PERCENT
1981	116,101	(2.3)	21,063	(3.2)	19,463	(2.0)	62.9
1982	117,004	0.8	21,273	1.0	19,713	1.3	62.8
1983	118,459	1.2	21,553	1.3	20,063	1.8	62.7
1984	121,114	2.2	21,893	1.6	20,403	1.7	63.0
1985	123,625	2.2	22,203	1.4	20,743	1.7	63.7
GROWTH 81-85		1.6		1.3		1.6	
1986	126,458	2.1	22,543	1.5	21,083	1.6	64.0
1987	128,767	1.8	22,893	1.6	21,493	1.9	64.2
1988	131,088	1.8	23,283	1.7	21,873	1.8	64.3
1989	133,340	1.7	23,643	1.5	22,283	1.9	64.4
1990	135,374	1.5	24,003	1.5	22,683	1.8	64.4
GROWTH 86-90		1.7		1.6		1.8	
GROWTH 81-90		1.7		1.5		1.7	

Based on NPCC ERA-411 Report dated April 1, 1981.

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Table 6B.6 indicates capacity reserve summer margins of 35.8% after maintenance and actual capacity reserves of 16.2% after considering forced outages and other unavailable capability.

TABLE 6B.6

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW YORK POWER POOL

	1981 SUMMER	1981 WINTER
1. PLANNED CAPABILITY (MW)	30363	31484
2. PEAK DEMAND (MW)	21063	19463
3. PLANNED RESERVES (MW)(1-2)	9300	12021
4. PLANNED RESERVES (%) (3/2) X 100	44.2	61.8
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	520	-31
6. TOTAL CAPABILITY (MW) (1+5)	30883	31453
7. TOTAL RESERVES (MW) (6-2)	9820	11990
8. TOTAL RESERVES (%) (7/2) X 100	46.6	61.6
9. SCHEDULED MAINTENANCE (MW)	2277	3400
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	28606	28053
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	7543	8590
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	35.8	44.1
13. FULL FORCED OUTAGES (MW)	2611	2204
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	25995	25849
15. AVAILABLE RESERVES (MW) (14-2)	4932	6386
16. AVAILABLE RESERVES (%) (15/2) X 100	23.4	32.8
17. OTHER UNAVAILABLE CAPABILITY (MW)	1518	2361
18. AVAILABLE CAPABILITY (MW) (14-17)	24477	23488
19. ACTUAL RESERVES (MW) (18-2)	3414	4025
20. ACTUAL RESERVES (%) (19/2) X 100	16.2	20.7

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	24477	23488
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	3414	4025
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	16.2	20.7

The Pool continues to experience transmission bottlenecks during off-peak periods in the Utica-Albany area as a result of operation of Oswego Union No. 6, and Ontario Hydro imports. There are, however, no major projects scheduled for completion during 1981. Transmission lines scheduled for completion during the period include 7.8 miles of 230 KV lines and 27.2 miles of 115/138 KV lines.

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Future Perspective

As shown in Table 6B.5, the forecasts for the 1981-1990 period indicate an increase in energy requirements at an average annual rate of 1.7 percent. Tables 6B.10.1, 16B.10.2, and 6B.10.3 show anticipated capacity reserve margins for the period 1982-1990. These reserve margins more than satisfy the NYPP Agreement criteria at present, but this relationship is sensitive to changes in the slippages presently being experienced for projects under construction given in Table 6B.7.

TABLE 6B.7

MAJOR FUTURE GENERATING UNIT IN-SERVICE DATES

NEW YORK POWER POOL

UTILITY	PLANT NAME	NAME PLATE CAPACITY (MW)	ORIGINAL IN-SERVICE DATE	IN-SERVICE DATE AS OF APRIL 1980	PRESENT IN-SERVICE DATE
		NUCLEAR			
LOIL	SHOREHAM #1	849	AUG 1970	MAY 1981	DEC 1982
NIMP	NINE MILE PT. #2	1166	APR 1979	NOV 1986	NOV 1986
		COAL			
NEYE	SOMERSET	850	OCT 1982	NOV 1984	NOV 1984
POAS	700 MW FOSSIL	700	SEP 1982	MAY 1987	MAY 1987
LOIL.NEYE	JAMESPORT #1	800	MAY 1989	MAY 1989	DEFERRED
		PUMPED STORAGE			
POAS	PRATTSVILLE	1000	MAY 1984	MAY 1987	MAY 1987

BASED ON ERA FORM 411

Tables 6B.7 also presents a breakdown by fuel type of the approximately 4,365 MW of new base load generating capacity scheduled to come on line between 1981 and 1990. This will include 2,015 MW nuclear, and 2,350 MW coal-fired plants. Tables 6B.11.1 and 6B.11.2 show nuclear capacity to increase from 11.8 percent in 1981 to 16.2 percent in 1990 and coal from 11.6 percent to 19.4 percent. The long range plans of the New York State Energy Office show greater emphasis on coal rather than nuclear with several oil-fired plants in the state scheduled for conversion to coal.

The New York State Energy Board, in its formal order on the state's first Energy Master Plan of March 20, 1981, opposed new nuclear plants at this time and proposed a state panel to evaluate nuclear power, including the potential impact of phasing down or eliminating existing plants. The New York Power Pool member plan included oil savings from increased conservation and management, the conversion of 3,281 MW in thirteen existing oil-fired plants to coal, the addition of 271 MW from small hydro-electric projects, the development of 397 MW by burning solid waste, and continued purchases of Hydro-Quebec power.

To meet the 1985 plant output of 123,825 GWH will require almost 18 million tons of coal, 40 million barrels of residual oil, and 850,000 barrels of distillate oil. The 1989 plant output of 135,374 GWH will require over 21 million tons of coal, 43 million barrels of residual oil, and 850,000 barrels of distillate oil.

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The only critical transmission project at present is the Lafayette-Oakdale 345 KV line due in 1982. This line will assist in reducing the Utica-Albany bottleneck which now limits increases in Canadian hydro imports.

Table 6B.8 shows transmission lines which are planned, committed, or under construction.

Table 6B.8

Planned, Under Construction, or Committed Transmission Lines
New York Power Pool

Year	Voltage (KV)	Lines
1981-1985	138/115	119.0
1986-1990	138/115	155.0
Total	138/115	274.1
1981-1985	230	7.8
1986-1990	230	0.0
Total	230	7.8
1981-1985	345	236.4
1986-1990	345	72.9
Total	345	309.3
1981-1985	500	0.0
1986-1990	500	0.0
Total	500	0.0
1981-1985	765	9.0
1986-1990	765	65.0
Total	765	74.0

Based on Form ERA-411.

TABLE 68.9

HISTORICAL CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW YORK POWER POOL

	1977		1978		1979		1980	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	29728	30856	29435	31125	30032	31083	30603	31700
2. PEAK DEMAND (MW)	21103	18838	20316	19598	20746	19417	21740	19865
3. PLANNED RESERVES (MW)(1-2)	8625	12018	9119	11527	9286	11666	8863	11835
4. PLANNED RESERVES (%) (3/2) X 100	40.9	63.8	44.9	58.8	44.8	60.1	40.8	59.6
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-130	-150	159	-150	668	-49	1400	837
6. TOTAL CAPABILITY (MW) (1+5)	29598	30706	29594	30975	30700	31034	32003	32537
7. TOTAL RESERVES (MW) (6-2)	8495	11868	9278	11377	9954	11617	10263	12672
8. TOTAL RESERVES (%) (7/2) X 100	40.3	63.0	45.7	58.1	48.0	59.8	47.2	63.8
9. SCHEDULED MAINTENANCE (MW)	0	0	0	0	0	0	3394	3812
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	29598	30706	29594	30975	30700	31034	28609	28725
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	8495	11868	9278	11377	9954	11617	6869	8860
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	40.3	63.0	45.7	58.1	48.0	59.8	31.6	44.6
13. FULL FORCED OUTAGES (MW)	0	0	0	0	0	0	2090	1051
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	29598	30706	29594	30975	30700	31034	26519	27674
15. AVAILABLE RESERVES (MW) (14-2)	8495	11868	9278	11377	9954	11617	4779	7809
16. AVAILABLE RESERVES (%) (15/2) X 100	40.3	63.0	45.7	58.1	48.0	59.8	22.0	39.3
17. OTHER UNAVAILABLE CAPABILITY (MW)	6434	5794	5841	8124	8264	8309	1598	1710
18. AVAILABLE CAPABILITY (MW) (14-17)	23164	24912	23753	22851	22436	22725	24921	25964
19. ACTUAL RESERVES (MW) (18-2)	2061	6074	3437	3253	1690	3308	3181	6099
20. ACTUAL RESERVES (%) (19/2) X 100	9.8	32.2	16.9	16.6	8.1	17.0	14.6	30.7

TABLE 6B.10.1

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW YORK POWER POOL

	1982		1983		1984	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	30380	32276	31180	32287	31193	32925
2. PEAK DEMAND (MW)	21273	19713	21553	20063	21893	20403
3. PLANNED RESERVES (MW)(1-2)	9107	12563	9627	12224	9300	12522
4. PLANNED RESERVES (%) (3/2) X 100	42.8	63.7	44.7	60.9	42.5	61.4
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	627	-173	627	-173	627	-173
6. TOTAL CAPABILITY (MW) (1+5)	31007	32103	31807	32114	31820	32752
7. TOTAL RESERVES (MW) (6-2)	9734	12390	10254	12051	9927	12349
8. TOTAL RESERVES (%) (7/2) X 100	45.8	62.9	47.6	60.1	45.3	60.5
9. SCHEDULED MAINTENANCE (MW)	2461	3486	2526	3487	2527	3559
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	28546	28617	29281	28627	29293	29193
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	7273	8904	7728	8564	7400	8790
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	34.2	45.2	35.9	42.7	33.8	43.1
13. FULL FORCED OUTAGES (MW)	2795	2259	2869	2260	2870	2305
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	25751	26358	26412	26367	26423	26888
15. AVAILABLE RESERVES (MW) (14-2)	4478	6645	4859	6304	4530	6485
16. AVAILABLE RESERVES (%) (15/2) X 100	21.1	33.7	22.5	31.4	20.7	31.8
17. OTHER UNAVAILABLE CAPABILITY (MW)	1519	2421	1559	2422	1560	2469
18. AVAILABLE CAPABILITY (MW) (14-17)	24232	23937	24853	23945	24863	24419
19. ACTUAL RESERVES (MW) (18-2)	2959	4224	3300	3882	2970	4016
20. ACTUAL RESERVES (%) (19/2) X 100	13.9	21.4	15.3	19.3	13.6	19.7

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	0	849	0	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	24232	23088	24853	23945	24863	24419
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	2959	3375	3300	3882	2970	4016
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	13.9	17.1	15.3	19.3	13.6	19.7

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TABLE 6B.10.2

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW YORK POWER POOL

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	31842	32585	31904	33948	34554	35632
2. PEAK DEMAND (MW)	22203	20743	22543	21083	22893	21493
3. PLANNED RESERVES (MW)(1-2)	9639	11842	9361	12865	11661	14139
4. PLANNED RESERVES (%) (3/2) X 100	43.4	57.1	41.5	61.0	50.9	65.8
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	627	-173	627	-173	627	-173
6. TOTAL CAPABILITY (MW) (1+5)	32469	32412	32531	33775	35181	35459
7. TOTAL RESERVES (MW) (6-2)	10266	11669	9988	12692	12288	13966
8. TOTAL RESERVES (%) (7/2) X 100	46.2	56.3	44.3	60.2	53.7	65.0
9. SCHEDULED MAINTENANCE (MW)	2579	3519	2584	3666	2799	3848
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	29890	28893	29947	30109	32382	31611
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	7687	8150	7404	9026	9489	10118
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	34.6	39.3	32.8	42.8	41.4	47.1
13. FULL FORCED OUTAGES (MW)	2929	2281	2935	2376	3179	2494
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	26961	26612	27012	27733	29203	29117
15. AVAILABLE RESERVES (MW) (14-2)	4758	5869	4469	6650	6310	7624
16. AVAILABLE RESERVES (%) (15/2) X 100	21.4	28.3	19.8	31.5	27.6	35.5
17. OTHER UNAVAILABLE CAPABILITY (MW)	1592	2444	1595	2546	1728	2672
18. AVAILABLE CAPABILITY (MW) (14-17)	25369	24168	25417	25187	27475	26445
19. ACTUAL RESERVES (MW) (18-2)	3166	3425	2874	4104	4582	4952
20. ACTUAL RESERVES (%) (19/2) X 100	14.3	16.5	12.7	19.5	20.0	23.0

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

	1985		1986		1987	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. NUCLEAR DELAYS (MW)	0	0	0	1166	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	25369	24168	25417	24021	27475	26445
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	3166	3425	2874	2938	4582	4952
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	14.3	16.5	12.7	13.9	20.0	23.0

TABLE 6B.10.3

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT)

NEW YORK POWER POOL

	1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY (MW)	34553	35569	34444	35611	34522	35568
2. PEAK DEMAND (MW)	23283	21873	23643	22283	24003	22683
3. PLANNED RESERVES (MW)(1-2)	11270	13696	10801	13328	10519	12885
4. PLANNED RESERVES (%) (3/2) X 100	48.4	62.6	45.7	59.8	43.8	56.8
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	627	-173	627	-173	627	-173
6. TOTAL CAPABILITY (MW) (1+5)	35180	35396	35071	35438	35149	35395
7. TOTAL RESERVES (MW) (6-2)	11897	13523	11428	13155	11146	12712
8. TOTAL RESERVES (%) (7/2) X 100	51.1	61.8	48.3	59.0	46.4	56.0
9. SCHEDULED MAINTENANCE (MW)	2799	3841	2790	3846	2796	3841
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	32381	31555	32281	31592	32353	31554
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	9098	9682	8638	9309	8350	8871
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	39.1	44.3	36.5	41.8	34.8	39.1
13. FULL FORCED OUTAGES (MW)	3179	2490	3169	2493	3176	2490
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	29202	29065	29112	29099	29177	29064
15. AVAILABLE RESERVES (MW) (14-2)	5919	7192	5469	6816	5174	6381
16. AVAILABLE RESERVES (%) (15/2) X 100	25.4	32.9	23.1	30.6	21.6	28.1
17. OTHER UNAVAILABLE CAPABILITY (MW)	1728	2668	1722	2671	1726	2668
18. AVAILABLE CAPABILITY (MW) (14-17)	27474	26397	27390	26428	27451	26396
19. ACTUAL RESERVES (MW) (18-2)	4191	4524	3747	4145	3448	3713
20. ACTUAL RESERVES (%) (19/2) X 100	18.0	20.7	15.8	18.6	14.4	16.4

EFFECT OF A SIX MONTH DELAY IN NUCLEAR COMPLETION

21. NUCLEAR DELAYS (MW)	0	0	0	0	0	0
22. ACTUAL CAPABILITY (MW) (18-21)	27474	26397	27390	26428	27451	26396
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (MW) (22-2)	4191	4524	3747	4145	3448	3713
24. ACTUAL RESERVES WITH NUCLEAR DELEAYS (%) (23/2) X 100	18.0	20.7	15.8	18.6	14.4	16.4

TABLE 6B.11.1

SUMMER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

NEW YORK POWER POOL

			OIL			NATURAL GAS			HYDRO		
YEAR	NUCLEAR STEAM	COAL STEAM	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	STEAM	COMBUST. TURBINE	INTERNAL COMBUST.	CONVENT.	PUMPED STORAGE	TOTAL CAPABILITY
1981	3594	3530	14725	3387	62	0	45	0	4020	1000	30363
% TOTAL	11.8	11.6	48.5	11.2	0.2	0.0	0.1	0.0	13.2	3.4	100.0
1982	3704	3530	14632	3387	62	0	45	0	4020	1000	30380
% TOTAL	12.2	11.6	48.2	11.2	0.2	0.0	0.1	0.0	13.2	3.3	100.0
1983	4517	3879	14250	3387	62	0	45	0	4020	1000	31180
% TOTAL	14.5	12.4	45.7	11.0	0.2	0.0	0.1	0.0	12.9	3.2	100.0
1984	4517	4299	13839	3387	62	0	45	0	4044	1000	31193
% TOTAL	14.5	13.8	44.3	10.9	0.2	0.0	0.1	0.0	13.0	3.2	100.0
1985	4517	4924	13849	3387	62	0	45	0	4058	1000	31842
% TOTAL	14.2	15.5	43.5	10.6	0.2	0.0	0.1	0.0	12.8	3.1	100.0
1986	4517	5296	13497	3387	62	0	45	0	4086	1000	31904
% TOTAL	14.2	16.6	42.4	10.6	0.2	0.0	0.1	0.0	12.8	3.1	100.0
1987	5597	5996	13343	3387	62	0	45	0	4124	2000	34554
% TOTAL	16.2	17.4	38.6	9.8	0.2	0.0	0.1	0.0	11.9	5.8	100.0
1988	5597	6736	12559	3387	62	0	45	0	4167	2000	34553
% TOTAL	16.2	19.5	36.3	9.8	0.2	0.0	0.1	0.0	12.1	5.8	100.0
1989	5597	6692	12491	3387	62	0	45	0	4170	2000	34444
% TOTAL	16.2	19.5	36.3	9.8	0.2	0.0	0.1	0.0	12.1	5.8	100.0
1990	5597	6684	12491	3387	62	0	45	0	4256	2000	34522
% TOTAL	16.2	19.4	36.2	9.8	0.2	0.0	0.1	0.0	12.3	5.8	100.0

BASED ON ERA FORM 411

TABLE 68.11.2

WINTER CAPABILITY BY FUEL TYPE (MW AND PERCENT)

NEW YORK POWER POOL

YEAR	NUCLEAR STEAM	COAL STEAM	OIL STEAM	OIL COMBUST. TURBINE	OIL INTERNAL COMBUST.	NATURAL GAS STEAM	NATURAL GAS COMBUST. TURBINE	NATURAL GAS INTERNAL COMBUST.	HYDRO CONVENT.	HYDRO PUMPED STORAGE	TOTAL CAPABILITY
1981	3719	3530	14767	4325	62	3	54	0	4024	1000	31484
% TOTAL	11.8	11.2	46.9	13.7	0.2	0.0	0.2	0.0	12.8	3.2	100.0
1982	4532	3524	14742	4325	62	3	54	0	4034	1000	32276
% TOTAL	14.0	10.9	45.7	13.4	0.2	0.0	0.2	0.0	12.5	3.1	100.0
1983	4532	3879	14368	4325	62	3	54	0	4064	1000	32287
% TOTAL	14.0	12.0	44.5	13.4	0.2	0.0	0.2	0.0	12.6	3.1	100.0
1984	4532	4924	13957	4325	62	3	54	0	4068	1000	32925
% TOTAL	13.8	15.0	42.4	13.1	0.2	0.0	0.2	0.0	12.4	3.0	100.0
1985	4532	4924	13605	4325	62	3	54	0	4080	1000	32585
% TOTAL	13.9	15.1	41.8	13.3	0.2	0.0	0.2	0.0	12.5	3.1	100.0
1986	5622	5291	13464	4325	62	3	54	0	4127	1000	33948
% TOTAL	17.1	16.1	40.9	13.1	0.2	0.0	0.2	0.0	12.5	3.0	100.0
1987	5622	6727	12671	4325	62	3	54	0	4168	2000	35632
% TOTAL	15.8	18.9	35.6	12.1	0.2	0.0	0.2	0.0	11.7	5.6	100.0
1988	5622	6727	12597	4325	62	3	54	0	4179	2000	35569
% TOTAL	15.8	18.9	35.4	12.2	0.2	0.0	0.2	0.0	11.7	5.6	100.0
1989	5622	6683	12597	4325	62	3	54	0	4265	2000	35611
% TOTAL	15.8	18.8	35.4	12.1	0.2	0.0	0.2	0.0	12.0	5.6	100.0
1990	5622	6648	12589	4325	62	3	54	0	4265	2000	35568
% TOTAL	15.8	18.7	35.4	12.2	0.2	0.0	0.2	0.0	12.0	5.6	100.0

BASED ON ERA FORM 411

SECTION XIV.7
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
(SERC)

[redacted]

Southeastern Electric Reliability Council (SERC)

Introduction

The Southeastern Electric Reliability Council (SERC) area includes all of the States of Alabama, Georgia, Florida, North Carolina, South Carolina and Tennessee and parts of Kentucky, Mississippi and Virginia. The SERC area covers about 10 percent of the nation's contiguous land area and provides about 20 percent of national electric energy requirements. Within SERC there are four Electric Regions: the Southern Co. (Region 9), which includes almost all of Georgia, most of Alabama, the Southeast one-quarter of Mississippi and the northwest corner of Florida; Florida (Region 7), which covers peninsular Florida; TVA (Region 11), which covers all of Tennessee and small parts of Alabama, Georgia, North Carolina, Mississippi and Kentucky; VACAR (Region 12), which includes most of North Carolina, South Carolina, most of Virginia and a small part of West Virginia. Each of these Electric Regions has its own unique characteristics which affects its electric bulk power supply.

The Southern Co. Region is a summer peaking region and the Florida Region is winter peaking. TVA has historically been a winter peaking region and VACAR has historically been a summer peaking region but the differences between summer and winter peaks in both of these regions are narrowing considerably. The fuel mixes in the Southern, TVA and VACAR Regions are similar. These Regions are heavily dependent upon coal for electric power generation. Most of the generating capacity in the Florida Region was originally designed to burn natural gas as a primary fuel with oil as an alternate fuel. The attrition of natural gas supplies coupled with the expiration of natural gas supply contracts has left the Florida Region heavily dependent upon high cost oil for electricity generation. Geographical location has not only affected the fuel mixes but has influenced the pattern of transmission development within and between each of the Electric Regions in SERC. TVA is very close to the geographical as well as the electrical center of the seven interconnected Reliability Council areas and is a key link between these areas. Consequently, an extensive 500 KV transmission network has been developed in the TVA Region. There is significant 500 KV in VACAR and in the Southern Co. Region, and a 500 KV transmission network is under development in Florida.

Assessment Methodology

The assessments in this report are based on information reported to the Department of Energy on Forms FPC 12E-2 and ERA-411 by the electric utilities.

The bulk power supply of each of the SERC Electric Regions was assessed within six broad categories, as follows:

1) Electric Load Growth
2) Generation Reserves
3) Generating Unit Delays
4) Load Relief Measures
5) Fuel Mix
6) Transmission

1. Electric Load Growth

The predicted growth rates for near-term and long-term electric energy and peak demand in comparison to that which was experienced between 1977 and 1980 are shown on Table 7.1 for each Electric Region in SERC.

Table 7.1

Historical and Future Load Growth Percentages by SERC Electric Regions

Item	Florida	Southern	TVA	VACAR
Annual Electric Energy				
1977-1980 (%) 1/	5.31	3.6	-0.6	3.6
1981-1985 (%) 1/	4.36	3.0	3.5	4.3
1986-1990 (%) 1/	3.39	3.3	4.4	4.0
Summer Peak Demand				
1977-1980 (%) 2/	5.62	6.0	2.3	3.2
1981-1985 (%) 1/	3.39	3.7	3.8	3.7
1986-1990 (%) 1/	2.59	3.4	4.7	3.8
Winter Peak Demand				
1977-1980 (%) 2/	10.33	3.2	-0.4	4.4
1981-1985 (%) 1/	2.85	3.8	2.0	4.4
1986-1990 (%) 1/	2.78	3.5	3.3	3.8

1/ From Form ERA-411
2/ From Form FPC 12E-2

The actual electric energy use for the last four years plus that forecasted by the electric utilities for the next ten years is shown by SERC Regions in Figure 7.1.

2. Generation Reserves

Generation reserve (actual) is measured by the difference between the system generating capability actually available to serve load and the peak demand. The actual reserves, as presently planned for the summer and winter peak load seasons for the next ten years in each of the SERC Regions, were developed based on the average generating capacity unavailable as a percent of installed generating capacity during the past four years and include the effect of scheduled purchases and sales of capacity. These percentages are shown on Table 7.2.

Table 7.2

Generating Capacity Unavailable as a Percent of Installed Capacity 1/

	Summer			Winter		
Electric Region	Maintenance Outage (%)	Full Forced (%)	Other Unavailable (%)	Maintenance Outage (%)	Full Forced (%)	Other Unavailable (%)
Florida	7.5	3.7	3.7	7.2	5.1	4.4
Southern	1.8	6.2	3.6	8.6	5.4	2.4
TVA	1.4	10.3	4.7	2.7	8.3	5.0
VACAR	5.9	5.8	7.8	6.4	5.4	8.4

1/ From Form FPC 12E-2 data for 1977 through 1980

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[redacted]

3. Generating Unit Delays

The estimated actual reserves are based on the timely installation of planned generating unit additions. Since about 1974 there have been numerous deferrals of planned generating capacity for various reasons.

Table 7.3 shows the average delay in planned nuclear and coal-fired generating unit in-service dates for units 300 MW and larger in SERC, measured by the difference in dates reported in the April 1980 ERA-411 and the April 1981 ERA-411.

Table 7.3

Nuclear and Coal-Fired Weighted Average Generating Unit Delay 1/ 2/

	Weighted Delay in Months from that Planned One Year Ago	
Electric Region	1981 - 1985	1986 - 1989
Florida	-0.4	3.9
Southern	12.6	0.0
TVA	15.5	25.2
VACAR	8.7	21.9

1/ Weighted Average Months Delay = $\frac{\sum \text{(MW x Months Delayed)}}{\sum \text{MW Delayed}}$

2/ April 1, 1981 ERA-411 and April 1, 1980, ERA-411.

[redacted]

4. Load Relief Measures

All of the SERC Regions employ load relief for situations where peak demand approaches or exceeds available generating capacity. For the sake of brevity, these measures are not discussed separately in the Regional sections of this report but are summarized collectively on Table 7.4.

Table 7.4

SERC Load Relief Measures and Estimated Relief in MW[1]

Type of Measure	Florida	Southern	TVA	VACAR
1. Adequacy Related				
a. Curtailment of non-essential utility load	24	75	35	16
b. Interruption of contract interruptible load	450	211	400	165
c. Voltage reduction	630	0	120	598
d. Public appeal	0	50	400	879
Total	1104	336	955	1658
2. Security Related				
a. Automatic underfrequency load shedding				
1. Step zero				
2. Step 1	2726	2000	2228	3224
3. Step 2	2739	2000	2163	3440
4. Step 3	4519	2000	3046	50
5. Step 4	0	1000	2531	3300
6. Step 5	0	0	0	170
7. Step 6	0	0	0	110
Total	9984	7000	9968	10294

[1] From Form ERA-411

[redacted]

5. Fuel Mix

Table 7.5 shows the planned 1990 fuel mix by capacity type for each of the SERC Regions.

Table 7.5

Installed Net Generating Capability By Energy Source (%) Winter Capability - 1990 1/

Electric Region	Nuclear	Coal-Fired	Oil-Fired	Hydro & Pumped Storage	Other
Florida	12.09	27.98	59.09	0.14	0.70
Southern	15.30	65.50	5.80	13.40	0.00
TVA	38.70	41.90	6.20	13.20	0.00
VACAR	32.40	45.30	11.20	11.10	0.00

1/ From Form ERA-411.

6. Transmission

The projected installed number of miles of 500 KV lines, at year-end, for each Region of SERC is shown on Table 7.6 for 1981 though 1990. The largest increase in EHV transmission in the Southeast is planned for Florida and between Florida and Southern.

Table 7.6

Projected Installed Miles of 500 KV lines in SERC - 1981-1990 1/

Year	Florida	Southern	TVA	VACAR	SERC
1981	440	1,108	2,183	1,499	5,230
1982	476	1,198	2,235	1,511	5,420
1983	512	1,335	2,241	1,511	5,599
1984	669	1,335	2,297	1,560	5,861
1985	894	1,440	2,394	1,837	6,565
1986	944	1,653	2,618	1,837	7,052
1987	1,363	1,775	2,618	1,902	7,658
1988	1,363	1,775	2,618	1,902	7,658
1989	1,415	1,775	2,708	1,993	7,891
1990	1,415	1,775	2,746	1,993	7,929

1/ From Form ERA-411

7.A Florida Coordinating Group (FCG) (Region 7)

Load growth in the Florida Coordinating Group Region has been moderating considerably during the past seven years as indicated by the change in forecast growth rates shown in Table 7.A.1. To further augment and accelerate the reduction in load growth, the State of Florida passed legislation during 1980 which required the Florida Public Service Commission (FPSC) to adopt conservation goals and approve utility plans to commence implementation by January 1, 1981. The current forecast for reporting year 1981 covering the period 1981 through 1990 reflects the state-mandated conservation program. A principal FPSC electric utility goal is reduction of the weather sensitive peak demand, both winter and summer. The actual load for the past four years and forecast loads for the next ten years, as developed by the electric utilities, are shown in Table 7.A.2.

[redacted]

Table 7.A.1

Projected Growth Rates As Reported by SERC
Florida Region

Reporting Year	Projected Years	Average Annual Growth Rate: Peak Demand: Summer	Peak Demand: Winter	Net Energy for Load
1974	1974-1983	10.6%	10.6%	10.0%
1975	1975-1984	7.6%	7.6%	7.3%
1976	1976-1985	6.5%	6.7%	6.4%
1977	1977-1986	5.5%	5.4%	5.4%
1978	1978-1987	5.1%	5.3%	5.0%
1979	1979-1988	4.7%	4.7%	4.5%
1980	1980-1989	4.6%	4.5%	4.4%
1981	1981-1990	2.9% 1/	2.8% 1/	3.8% 1/

1/ Reflects mandatory conservation effects under the 1980 Florida Energy Efficiency and Conservation Act.

Table 7.A.2

Annual Growth of Electric Energy and Seasonal Peak Demand
Florida Region, 1977-1990

Year	Annual Electric Energy (GWH)	Annual Electric Energy Growth (%)	Summer Peak Demand (MW)	Summer Peak Demand Growth (%)	Winter Peak Demand (MW)	Winter Peak Demand Growth (%)	Annual Load Factor (%)
-Actual-							
1977	79897	-	15513	-	17012	-	53.61
1978	84868	6.22	16108	3.84	17465	2.66	55.47
1979	87729	3.37	16605	3.09	18142	3.88	60.31
1980	93300	6.35	18254	9.93	22576	1.24	47.18
% Growth 1977-1980		5.31		5.62		10.33	
-Forecast-							
1981	96979	-	18577	-	20880	-	53.02
1982	101795	4.97	19383	4.34	21658	3.73	53.65
1983	106605	4.73	20046	3.42	22176	2.39	54.88
1984	111036	4.16	20759	3.56	22830	2.95	55.52
1985	114990	3.56	21225	2.24	23365	2.34	56.18
% Growth 1981-1985		4.36		3.39		2.85	
1986	119176	3.64	21806	2.74	23893	2.26	56.94
1987	123212	3.39	22420	2.82	24586	2.90	57.21
1988	127455	3.44	22932	2.28	25133	2.22	57.89
1989	131693	3.33	23502	2.49	25861	2.90	58.13
1990	135850	3.16	24120	2.63	26791	3.60	57.89
% Growth 1986-1990		3.39		2.59		2.78	
% Growth 1981-1990		3.88		2.99		2.81	

[redacted]

Projected reserves for Florida over the next ten years are shown in Table 7.A.4 (1981 through 1985) and Table 7.A.5 (1986 through 1990); the reserves are shown graphically in Figure 7.A.1.

The reserve outlook is based on the load forecasts and on the timely installation of future generating units. Table 7.A.3 lists the major (300 MW and over) nuclear and coal-fired generating units planned for future service and the delays experienced during the last year.

Table 7.A.6 (summer) and Table 7.A.7 (winter) show planned installed capability by fuel type for the Florida Region for 1981 through 1990. Figure 7.A.2 gives a graphical representation of the installed fuel mix for Florida covering 1981 through 1990.

The high dependence upon oil for fuel in peninsular Florida was caused by the sudden withdrawal of natural gas supplies. While the Florida electric utilities are trying to reduce oil consumption, natural gas contracts continue to expire, nullifying the influence of oil conservation efforts.

The Florida Public Service Commission (FPSC) is investigating the development and implementation of rate making incentives which would allow the electric utilities in Florida to install facilities, over and above those needed for load growth, which will economically displace oil and provide savings to customers. 1/ A recent study completed by the Florida Coordinating Group (FCG) to determine the amount of coal-fired generating capacity which could economically be added to reduce oil use indicated that total generation reserves of between 50% and 80% were economically justifiable for peninsular Florida during the 1986-1990 period and that coal-fired generation unit capacity factors below 40% were also economically justified. 2/

The Florida and Southern Regions have undertaken a large joint transmission plan. Florida's portion of the intertie program involves the construction of 975 miles of 500 KV lines. This expansion was largely justified by the projected transfer of "coal by wire" power from Southern to Florida to displace oil use in Florida.

Table 7.A.3

Planned Nuclear and Coal-Fired Generating Units Over 300 Mw

Florida Region

Unit Designation	Capacity in Mw	Fuel Type	Planned In-Service Date As of 4/80	Planned In-Service Date As of 4/81	Change in Mw-Months
McIntosh No. 3	334	Coal	10/81	10/81	0
Crystal River No. 4	640	Coal	12/82	12/82	0
St. Lucie No. 2	729	NUC	11/83	6/83	(3,645)
Seminole No. 1	600	Coal	5/83	6/83	600
Crystal River No. 5	640	Coal	6/84	12/84	3,840
Seminole No. 2	600	Coal	5/85	1/85	(2,400)
Big Bend No. 4	417	Coal	3/85	3/85	0
St. Johns River No. 1	550	Coal	12/85	12/85	0
Stanton No. 1	355	Coal	5/86	11/86	2,130
Martin No. 3	700	Coal	6/87	6/87	0
St. Johns River No. 2	550	Coal	6/87	6/87	0
McInnes No. 1	400	Coal	-	3/89	0
Martin No. 4	700	Coal	6/88	6/89	8,400

1/ Letter dated April 20, 1981, from Florida Public Service Commission staff representative.

2/ "Peninsula Florida Economic Oil Displacement Study," dated March 18, 1981.

7.B. Southern Companies (Region 9)

Energy usage and peak demand growth rates have been decreasing since 1974. The declining council forecasts are presented in Table 7.B.1. As indicated in the ERA-411 Report, the task of utility forecasting has been made more difficult due to the unknown influences of conservation, the state of the economy and price elasticity on future load and demand. The actual load for the past four years and forecast load for the next ten years, as developed by the electric utilities, is shown in Table 7.B.2. The reserve picture in this region appears to be adequate for the next 10 years. (See Tables 7.B.4, 7.B.5, and Figure 7.B.1.) Table 7B.3 lists the 300 MW and larger coal units planned for 1981-1990 and shows delays that have occurred. The generation fuel mix for this region shown in Tables 7.B.6, 7.B.7 and Figure 7.B.2 shows the high percentage of capacity vested in coal-fired units. Among the four regions of SERC, the Southern Companies Region has the highest percentage of its total electric production facilities using coal as the primary fuel. In 1980, 64% of the region's power production was coal-fired generation. Figure 7.B.2 shows that coal will fuel over 60% of the generating facilities in the region during the next decade.

Table 7.B.1

Projected Growth Rates as Reported by SERC

Southern Companies Region

Reporting Year	Projected Years	Average Annual Growth Rate (%) Peak Demand Summer	Average Annual Growth Rate (%) Peak Demand Winter	Average Annual Growth Rate (%) Net Energy for Load
1974	1974-1983	10.0	9.4	9.8
1975	1975-1984	9.7	9.1	9.4
1976	1976-1985	7.9	7.7	7.8
1977	1977-1986	7.6	7.2	7.6
1978	1978-1987	6.5	6.7	6.5
1979	1979-1988	5.0	5.4	5.2
1980	1980-1989	4.1	4.6	4.1
1981	1981-1990	3.5	3.6	3.5

[redacted]

Table 7.B.2

Annual Growth of Electric Energy and Seasonal Peak Demand - 1977-1990

Southern Companies Region

Year	Annual Electric Energy (GWH)	Annual Electric Energy Growth (%)	Summer Peak Demand (MW)	Summer Peak Demand Growth (%)	Winter Peak Demand (MW)	Winter Peak Demand Growth (%)	Annual Load Factor (%)
-Actual-							
1977	98169	-	19125	-	16705	-	58.6
1978	102451	4.4	20464	7.0	17374	4.0	57.1
1979	103066	0.4	20432	-0.2	16969	-2.3	57.6
1980	109187	5.9	22690	11.1	18320	8.0	54.9
% Growth 1977-1980		3.6		6.0		3.2	
-Forecast-							
1981	107517	-	21101	-	18136	-	
1982	111667	3.9	21742	3.0	18902	4.2	
1983	116151	4.0	22689	4.4	19657	4.0	
1984	120485	3.7	23532	3.7	20328	3.4	
1985	124733	3.5	24401	3.4	21043	3.5	
% Growth 1981-1985		3.0		3.7		3.8	
1986	129082	3.8	25251	3.5	21774	3.5	
1987	134339	4.1	26256	4.0	22721	4.4	
1988	137739	2.5	26970	2.7	23341	2.7	
1989	142110	5.8	27866	3.3	24102	3.3	
1990	146766	3.3	28854	3.6	24932	3.4	
% Growth 1986-1990		3.3		3.4		3.5	
% Growth 1981-1990		3.5		3.5		3.5	

Table 7.B.3

Planned Nuclear and Coal-Fired Generating Units Over 300 Mw

Southern Companies Region

Unit Designation	Capacity in Mw	Fuel Type	Planned In-Service Date As of 4/80	Planned In-Service Date As of 4/81	Change in Mw-Months
Farley 2	807	UR	9/80	7/81	8,070
Miller 2	654	BIT	6/83	5/85	15,042
Miller 3	654	BIT	6/85	6/89	31,392
Scherer 1	808	BIT	2/82	2/82	0
Scherer 2	808	BIT	2/84	2/84	0
Vogtle 1	1,150	UR	11/84	5/85	6,900
Schere 3	808	BIT	2/87	2/87	0
Vogtle 2	1,150	UR	11/87	11/87	0
Schere 4	808	BIT	2/89	2/89	0
Daniels 2	503	BIT	6/81	6/81	0
Unnamed 1	370	COL	Not Listed	6/87	-

Utilities within the Southern Companies Region have entered into an agreement with utilities in the Florida Region to build two 500 KV transmisshon lines linking the two regions. The agreement also states that the Southern Companies region will supply electric energy provided by coal-fired units to Florida utilities that would otherwise generate their electric energy by burning imported oil. This arrangement will continue through 1992.

The agreements to construct the 500 KV lines between the Southern and Florida Regions will complete a strong EHV system running between north and south within the area of the two regions. Additional transmission interconnections between Southern and the VACAR Region on the eastern boundary, and the Southwest Power Pool on the western boundary, are under study.

7.C. Tennessee Valley Authority (TVA) (Region 11)

TVA's load and energy forecasted growth rates have been declining from 1975 to 1978 with the forecasted growth rates leveling off the last two years as indicated by Table 7.C.1. As indicated in the ERA-411 Report, due to uncertainty in forecasting future demand and energy, TVA is now using a "high" and "low" estimating procedure. This type of forecasting deals with the uncertainty by producing a range of forecasts based on the alternative levels of the major factors which determine load growth. This procedure bounds the range of the forecasts between the so-called best case and worst case situations. All forecasted values from 1981 through 1990 used in this report are from the "high" forecast unless otherwise noted. The actual load for the past four years and forecast load for the next ten years, as developed by the electric utilities, is shown in Table 7.C.2.

Table 7.C.1

Projected Growth Rates As Reported by SERC

TVA Region

Reporting Year	Projected Years	Average Annual Growth Rate (%) Peak Demand Summer	Peak Demand Winter	Net Energy for Load
1974	1974-1983	5.6	5.6	4.9
1975	1975-1984	6.3	6.3	6.6
1976	1976-1985	5.8	5.5	5.6
1977	1977-1986	5.5	5.7	5.5
1978	1978-1987	5.9	5.7	5.5
1979	1979-1988	5.2	5.2	5.0
1980	1980-1989	3.8	3.4	3.9
1981	1981-1990	4.3	3.1	4.0

Table 7.C.2

Annual Growth of Electric Energy and Seasonal Peak Demand 1977-1990

TVA Region

Year	Annual Electric Energy (GWH)	Annual Electric Energy Growth (%)	Summer Peak 1/ Demand (MW)	Summer Peak 1/ Demand Growth (%)	Winter Peak 1/ Demand (MW)	Winter Peak 1/ Demand Growth (%)	Annual Load Factor (%)
			-Actual-				
1977	126333	-	18953	-	21992	-	65.5
1978	122768	-2.8	18600	-1.9	21540	-2.1	65.1
1979	122369	0.5	18795	1.1	20745	-3.7	67.9
1980	123877	0.4	20250	7.7	21694	4.6	65.2
% Growth 1977-1980	122768	-0.6		2.3		-0.4	
			-Forecast-				
1981	120049	-	20016	-	21993	-	
1982	126248	5.2	21199	5.9	22477	2.2	
1983	128723	2.0	21756	2.6	22965	2.2	
1984	132428	2.9	22341	2.7	23672	3.1	
1985	137618	3.9	23212	3.9	24617	4.0	
% Growth 1981-1985		3.5		3.8		2.9	
1986	145912	6.0	24449	5.3	26046	5.8	
1987	155644	6.7	26158	7.0	26826	3.0	
1988	160969	3.4	27119	3.7	27592	2.9	
1989	165355	2.7	28109	3.7	28401	2.9	
1990	170409	3.1	29181	3.8	28888	1.7	
% Growth 1986-1990		4.4		4.7		3.3	
% Growth 1981-1990		4.0		4.3		3.1	

1/ TVA Region peak month

This forecasting procedure indicates the difficulty in linking the uncertainties of load and energy forecasts to construction of electrical plant. The "high" and "low" forecasted values for energy and the difference between the uncertainties of the "high" and "low" forecasts are:

Net Energy Forecast (GWH)

Year	"High" Forecast	"Low" Forecast	Difference As % of Low
1981	120049	117602	2.1%
1985	137618	126087	9.1%
1990	170419	141759	20.2%

These figures indicate that the uncertainty involved in a decision to start building electrical plant in 1980 for use in 1990 may be more than twice as great as the uncertainty related to a decision to start building electrical plant in 1980 for use in 1985.

Tables 7.C.4, 7.C.5, and Figure 7.C.1 show that the forecasted TVA reserves at peak load will be adequate for the next decade. The tables and graph assume that that the unavailable capacity during peak will remain a constant percentage of the installed capacity throughout the decade.

[redacted]

Tables 7.C.3 shows the changes in completion dates of future units. Four units, totaling 4,984 MW, have been suspended with the completion dates dependent on the availability of more accurate data regarding future load growth. TVA's only projected units are of the nuclear type.

Table 7C.3

Planned Nuclear Generating Units For 1981-1990 1/

TVA Region

Unit Designation	Capacity in MW	Fuel Type	Planned In-Service Date As of 4/80	Planned In-Service Date As of 4/81	Change in MW - Months
Sequoyah 1	1148	UR	06/80	03/81	10332
Sequoyah 2	1148	UR	06/81	07/82	14924
Watts Bar 1	1177	UR	09/81	11/82	16478
Watts Bar 2	1177	UR	06/82	08/83	16478
Bellefonte 1	1213	UR	09/83	12/85	32751
Bellefonte 2	1213	UR	06/84	09/86	32751
Yellow Creek 1	1285	UR	11/85	04/88	39835
Phipps Bend 1	1233	UR	03/87	02/89	28359
Hartsville A 1	1233	UR	07/86	07/88	29592
Hartsville A 2	1233	UR	07/87	04/89	25893
Hartsville B 1	1233	UR	06/89	Suspended	-
Hartsville B 2	1233	UR	06/90	Suspended	-
Phipps Bend 2	1233	UR	08/89	Suspended	-
Yellow Creek 2	1285	UR	04/88	Suspended	-

1/ The only generating units projected by TVA for 1981-1990 completion are the nuclear units listed in this table.

The TVA Region's generation fuel mix, illustrated in Figure 7.C.2 and presented in Tables 7.C.6 and 7.C.7, indicates the planned nuclear facilities building program that will be implemented by TVA during the next decade. In 1981, nuclear generation is scheduled to provide 15.4% of the region's capability; nuclear generation is scheduled to provide 39.0% of the total capability by 1990. If the nuclear program continues as presently scheduled, the TVA Region will have in 1990 a generation mix with 39% of the generating capacity vested in nuclear facilities, 41% in coal burning facilities, 15% in hydro driven generators and only 5% in oil.

In an attempt to introduce the more economic forms of electric generation into the fuel generation mix, TVA has thoroughly investigated the potential for cogeneration in the region. As a result of these studies (reported in TVA's "Preliminary Assessment of Cogeneration Potential in the TVA Region") TVA has developed a 3-year test program whereby TVA personnel are providing industries in the region with assistance in development of cogeneration potential, and TVA has developed electric rates for paying for power and energy received from industrial cogeneration plants. The region's industrial plants that currently have in-plant cogeneration are using their entire generation for their own uses and no electric energy is being transferred to the TVA grid. Of the potential cogeneration facilities that have been recently identified, the majority will produce power and energy for in-plant use only. Some installations have indicated that they desire to produce power and energy for sale to the TVA system. The exact amounts of cogenerated capacity and energy that will be sold to TVA will not be known until late 1981. TVA also investigated the possibility of increasing steam capacity in existing TVA electric generating units for possible cogeneration. It was

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found that this potential is extremely limited because the modifications that would be required to increase steam production would be very costly and would reduce the generating capabilities of the existing units. TVA also investigated the possibility of creating a large energy park. It was determined that, theoretically, 9,000 MW of cogeneration could be produced by such an installation. However, to achieve this, numerous constraints must be dealt with and needed resources such as land, financing, labor, coal, raw material, and a long term stable market, must be established and combined.

Of all the Regions in SERC, the TVA Region has the highest percentage of total capacity produced by hydro facilities (approximately 16% in 1980). The TVA Region will continue to have a significant percentage of its total capacity in hydro facilities during the 1981-1990 decade (approximately 15% for 1990). The TVA Region has been experiencing a severe drought during the last year. It is anticipated that a drought of this magnitude will result in a 1.9% reduction of hydro-generated capacity and a 12.5% reduction of hydro energy production. A severe drought in the TVA Region will also reduce the capabilities of numerous steam generating plants by limiting the amount of cooling water available for the condensing portion of the steam cycle. The lost energy production and capacity could be provided by purchases from contiguous utilities utilizing the extensive transmission system that has been developed by TVA, if those utilities have energy and capacity available.

TVA has developed very strong EHV interties with all contiguous Reliability Councils and SERC Regions except for the VACAR Region. TVA has completed near term and long-term studies with MAIN and ECAR; based on the studies it is believed that the bulk power supply can be expected to withstand severe disturbances without experiencing cascading outages. TVA periodically does transmission studies with the Southern and VACAR Regions. These studies have indicated that no short-term problems are evident.

7.D Virginia-Carolinas (VACAR) (Region 12)

The VACAR Region is the largest of the four Electric Regions in the SERC area from the standpoint of peak demand and net energy. VACAR's demand and energy requirements amount to approximately one third of the SERC total for 1981 and are projected to maintain that ratio through 1990. The VACAR utilities made a heavy commitment to nuclear units in the early 1970's and with adjustments dictated by growth patterns, this commitment continues through 1990. Table 7.D.3 shows the large number of planned future nuclear units over 300 MW.

Table 7.D.1 shows the projected growth rate for each of the last eight reporting years. The projected percent rate of growth has steadily declined from 9.2 percent in 1974 to 3.8 percent in 1981 for summer peak demands. Table 7.D.2 summarizes the growth rate with the actual values for the 1977-80 period and the projected values for the 1981-90 period.

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Table 7.D.1

Projected Growth Rates As Reported by SERC

VACAR Region

Reporting Year	Projected Years	Average Annual Growth Rate - (%) Peak Demand Summer	Peak Demand Winter	Net Energy for Load
1974	1974-1983	9.2	9.3	9.0
1975	1975-1984	8.3	8.6	8.1
1976	1976-1985	6.9	7.6	6.8
1977	1977-1986	6.3	7.1	6.8
1978	1978-1987	6.0	6.2	6.3
1979	1979-1988	6.0	6.0	6.1
1980	1980-1989	4.8	5.0	4.8
1981	1981-1990	3.8	4.1	4.1

Table 7.D.2

Annual Growth of Electric Energy and Seasonal Peak Demand 1977-1990

VACAR Region

Year	Annual Electric Energy (GWH)	Growth (%)	Summer Peak Demand 1/ (MW)	Growth (%)	Winter Peak Demand 1/ (MW)	Growth (%)	Annual Load Factor (%)
-Actual-							
1977	137770	-	26370	-	25814	-	59.6
1978	143026	3.8	26200	-0.7	26063	0.9	62.3
1979	144934	1.3	27489	4.7	26627	1.7	60.2
1980	153351	5.8	29029	5.6	29461	10.7	59.4
% Growth 1977-1980		3.6		3.2		4.4	
-Forecast-							
1981	155394	-	29302	-	29150	-	59.7
1982	160696	3.4	30232	3.2	30700	5.3	59.7
1983	170688	6.2	31453	4.0	31994	4.2	60.9
1984	177017	3.7	32715	4.0	33266	4.0	60.7
1985	183911	3.9	33961	3.8	34556	3.9	60.7
% Growth 1981-1985		4.3		3.7		4.4	
1986	191213	4.0	35271	3.9	35854	3.8	60.9
1987	198825	4.0	36625	3.8	37174	3.7	61.1
1988	207426	4.5	38034	3.8	38643	3.9	61.1
1989	215560	3.9	39436	3.7	40162	3.9	61.3
1990	223655	3.8	40918	3.8	41657	3.7	61.3
% Growth 1986-1990		4.0		3.8		3.8	
% Growth 1981-1990		4.2		3.8		4.1	

1/ VACAR Region peak month.

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Tables 7.D.4 and 7.D.5 tabulate the future generating capability and reserves for 1981 through 1990. To determine actual reserves, historical data were developed from FPC Form 12E-2 for the various categories of unavailable capacity at time of peak, line (9), (13), and (17) of Tables 7.D.4 and 7.D.5.

Table 7.D.3 lists the nuclear and coal-fired units over 300 MW capacity scheduled to be placed in service between 1981 and 1990. Pumped storage hydro is included in Table 7.D.5 to show the overall fuel mix for this period of time. The in-service date for most of the new capacity has slipped since the 1980 ERA-411.

Table 7.D.3

Planned Generating Units Over 300 MW

VACAR Region

Unit Designation	Capacity in MW	Fuel Type	Planned In-Service Date As of 4/80	Planned In-Service Date As of 4/81	Change in MW - Months
McGuire No. 1	1180	Nu	12/80	07/81	8260
Summer No. 1	900	Nu	12/80	06/82	16200
Mayo No. 1	720	Coal	03/83	03/83	0
McGuire No. 2	1180	Nu	07/82	06/83	12980
Cross Site No. 2	450	Coal	11/83	11/83	0
Catawba No. 1	1145	Nu	12/83	03/84	3435
Harris No. 1	900	Nu	03/84	09/85	16200
Catawba No. 2	1145	Nu	07/85	09/85	2290
Bath County No. 1, 2, 4	525	P.S.	12/83	10/85	11550
Bath County No. 3, 5, 6	525	P.S.	04/84	10/86	15750
Cross Site No. 1	450	Coal	11/86	11/86	0
Harris No. 2	900	Nu	03/87	03/88	10800
Unsited	500	Coal	05/87	05/88	6000
Cross Site No. 3	450	Coal	11/88	11/88	0
North Anna No. 3	907	Nu	10/87	10/89	21768
Mayo No. 2	720	Coal	03/85	03/90	43200
Bad Creek No. 1, 2	500	P.S.	-	04/90	0
Cross Site No. 4	450	Coal	-	11/90	0

Tables 7.D.6 and 7.D.7., and Figure 7.D.2 show the net generating capability by fuels. It should be noted that even though the various oil-fired units represent 16.3 percent of the total capability for summer 1981, only 4.3 percent of the energy requirement for the peak month is projected to be from this source. Oil consumption shows a steady decline in VACAR and should continue so through the 1980's.

The import/export capability in the VACAR Subregion is quite strong. At the time of the extremely hot 1980 summer peak load, the Region imported 4,189 MW of capacity, or 14.4 percent of the load requirements. This should be considered in evaluating the actual reserves shown in Tables 7.D.4, 7.D.5, and Figure 7.D.1.

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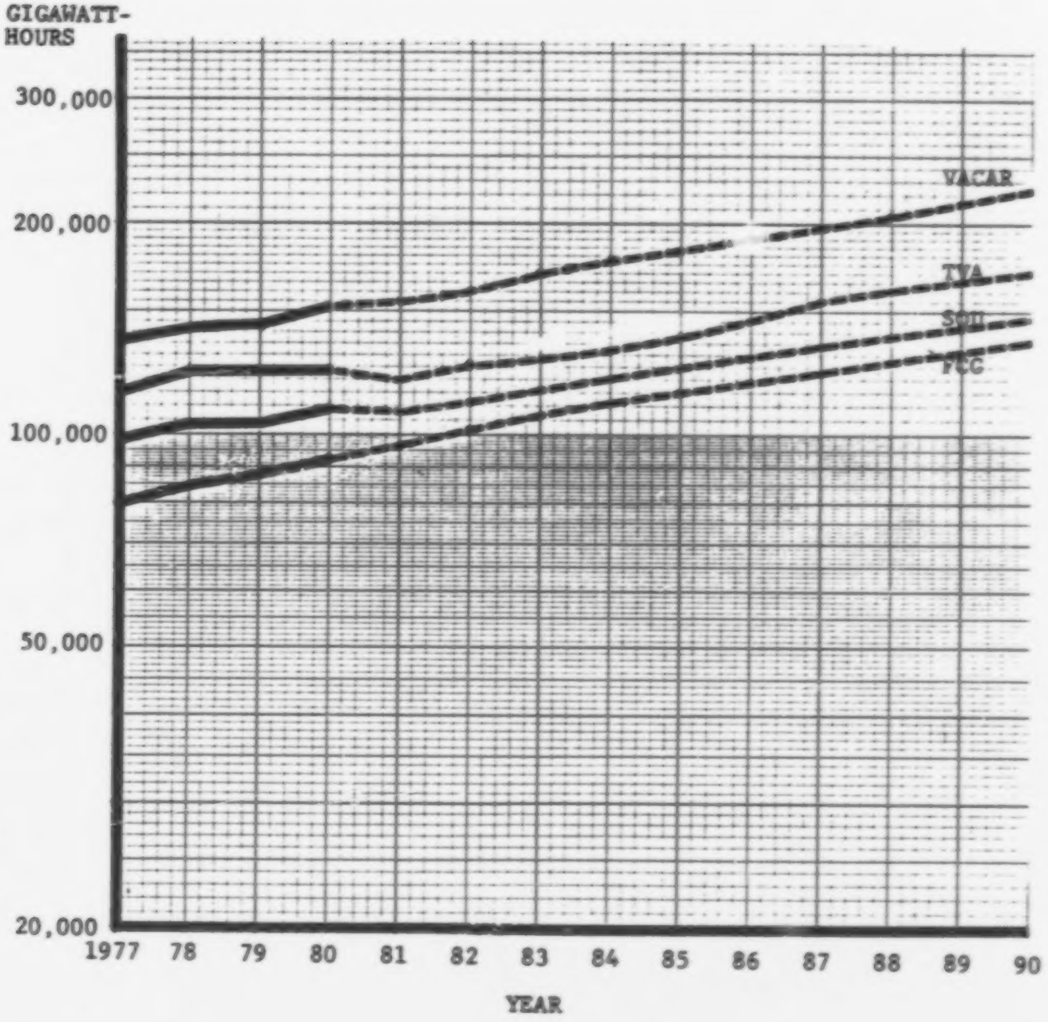
Figure 7.1

Actual and Forecast Electric Energy Use

Electric Regions In SERC



Based on SERC ERA-411 Reports.

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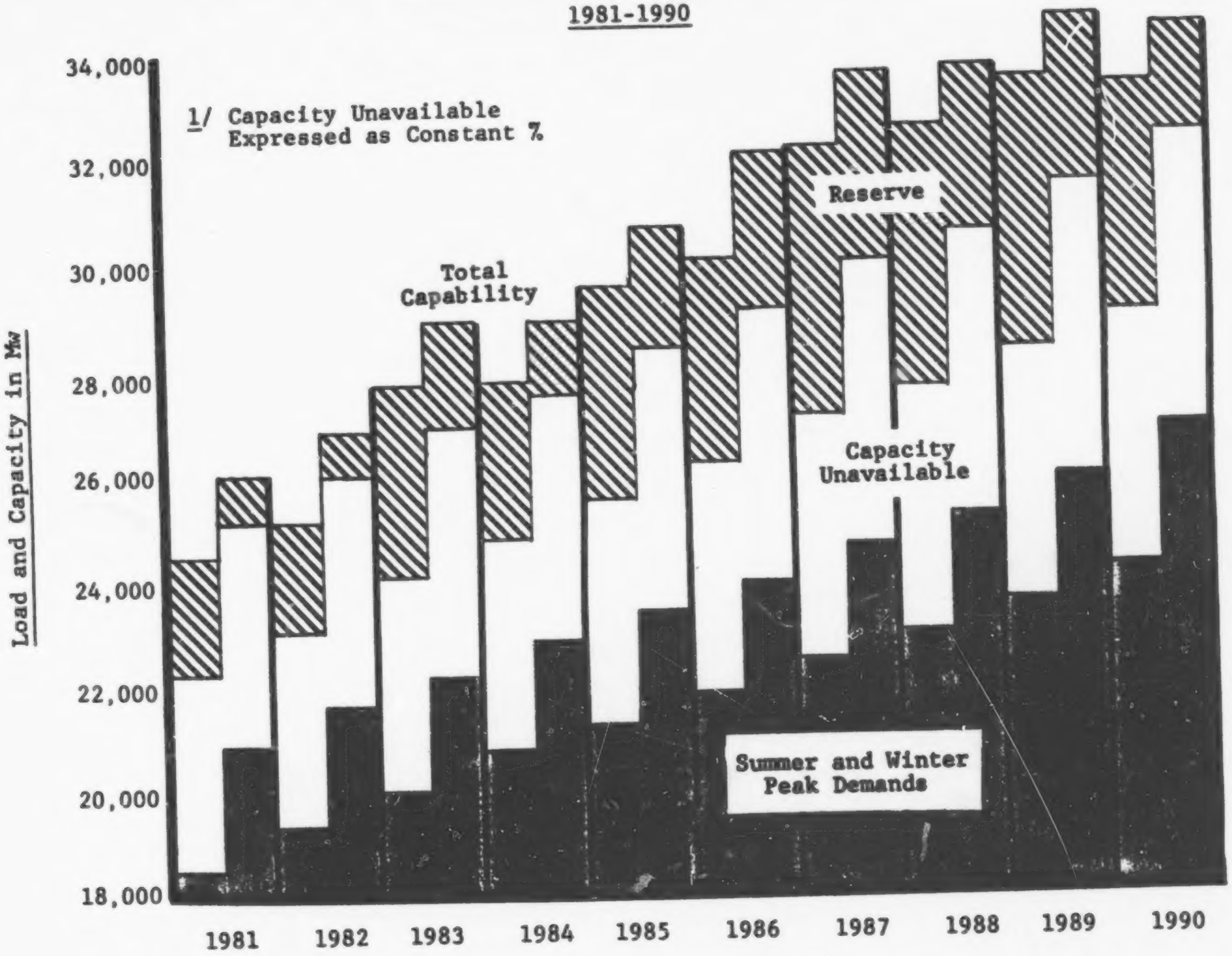
Figure 7.A.1

Florida Generation Reserve Outlook 1/

1981-1990



Based on SERC ERA-411 Report dated April 1, 1981.

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Table 7.A.4

Future Generating Capability (Mw) and Reserves (Mw and Percent) - 1981-1985

Florida Region

Mw or Percent	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	24,529	26,058	25,150	26,190	27,041	28,233	27,071	28,217	28,843	29,981
2. Peak Demand	18,577	20,880	19,383	21,658	20,046	22,176	20,759	22,830	21,225	23,365
3. Planned Reserve (1-2)	5,952	5,178	5,767	4,532	6,995	6,057	6,312	5,387	7,618	6,616
4. Planned Reserve (%) (3/2) x 100	32.0	24.8	29.8	20.9	34.9	27.3	30.4	23.6	35.9	28.3
5. Net Transactions (Imports-Exports)	24,529	26,058	25,150	26,840	27,691	28,883	27,721	28,867	29,493	30,631
6. Total Capability (1+5)	5,952	5,178	5,767	5,182	7,645	6,707	6,962	6,037	8,268	7,266
7. Total Reserves (6-2)	32.0	24.8	29.8	23.9	38.1	30.2	33.5	26.4	39.0	31.1
8. Total Reserve (%) (7/2) x 100	0	0	0	650	650	650	650	650	650	650
9. Scheduled Maint. 2/	1,840	1,876	1,886	1,886	2,028	2,033	2,030	2,032	2,163	2,159
10. Capability after Main. (6-9)	22,689	24,182	23,264	24,954	25,663	26,850	25,691	26,835	27,330	28,472
11. Reserve after Maint. (10-2)	4,112	3,302	3,880	3,296	5,617	4,674	4,932	4,005	6,105	5,107
12. Reserv.aft.Maint.(%) (11/2) x 100	22.1	15.8	20.0	15.2	28.0	21.1	23.8	17.5	28.8	21.9
13. Full Forced Outage 2/	908	1,329	931	1,336	1,001	1,440	1,002	1,439	1,067	1,529
14. Cap.aft. F.O. (10-13)	21,782	22,853	22,333	23,619	24,662	25,410	24,689	25,396	26,263	26,943
15. Avail. Reserve (14-2)	3,205	1,973	2,950	1,961	4,616	3,234	3,930	2,566	5,038	3,578
16. Avail. Reserve (%) (15/2) x 100	17.3	9.4	15.2	9.1	23.0	14.6	18.9	11.2	23.7	15.3
17. Other Unavailable 2/	908	1,147	931	1,152	1,001	1,242	1,002	1,242	1,067	1,319
18. Actual Capability Avail. (14-17)	20,874	21,706	21,403	22,466	23,662	24,168	23,687	24,155	25,195	25,624
19. Actual Reserves (18-2)	2,297	826	2,020	808	3,616	1,992	2,928	1,325	3,970	2,259
20. Actual Reserve (%) (19/2) x 100	12.4	4.0	10.4	3.7	18.0	9.0	14.1	5.8	18.7	9.7

1/ Assumes no new unit delays.

2/ Maintenance outages, other unavailable capacity and forced outages were derived from historic data and are actual average values which occurred between 1977 and 1980 at the time of the respective summer and winter seasonal peak demands expressed in constant percentage of planned capability.

Based on SERC ERA-411 Report dated April 1, 1981.

Table 7.A.5

Future Generating Capability (Mw) and Reserves (Mw and Percent) - 1986-1990

Florida Region

Mw or Percent	1986 Summer	1986 Winter	1987 Summer	1987 Winter	1988 Summer	1988 Winter	1989 Summer	1989 Winter	1990 Summer	1990 Winter
1. Planned Capability 1/	29,356	30,854	30,961	32,114	31,069	32,203	31,988	33,123	31,865	32,946
2. Peak Demand	21,805	23,893	22,420	24,586	22,932	25,133	23,502	25,861	24,120	26,791
3. Planned Reserve (1-2)	7,551	6,961	8,541	7,528	8,137	7,070	8,486	7,262	7,745	6,155
4. Planned Reserve (%) (3/2) x 100	34.6	29.1	38.1	30.6	35.5	28.1	36.1	28.1	32.1	23.0
5. Net Transactions (Imports-Exports)	650	1,150	1,150	1,400	1,400	1,400	1,400	1,400	1,400	1,400
6. Total Capability (1+5)	30,006	32,004	32,111	33,514	32,469	33,603	33,388	34,523	33,265	34,346
7. Total Reserves (6-2)	8,201	8,111	9,691	8,928	9,537	8,470	9,886	8,662	9,145	7,555
8. Total Reserve (%) (7/2) x 100	37.6	33.9	43.2	36.3	41.6	33.7	42.1	33.5	37.9	28.2
9. Scheduled Maint. 2/	2,202	2,222	2,322	2,312	2,330	2,319	2,399	2,385	2,390	2,372
10. Capability after Main. (6-9)	27,804	29,783	29,789	31,202	30,139	31,284	30,989	32,138	30,875	31,974
11. Reserve after Maint. (10-2)	5,999	5,890	7,369	6,616	7,207	6,151	7,487	6,277	6,755	5,183
12. Reserv.aft.Maint.(%) (11/2) x 100	27.5	24.6	32.9	26.9	31.4	24.5	31.9	24.3	28.0	19.3
13. Full Forced Outage 2/	1,086	1,574	1,146	1,638	1,150	1,642	1,184	1,689	1,179	1,680
14. Cap.aft. F.O. (10-13)	26,718	28,209	28,643	29,564	28,989	29,642	29,805	30,449	29,696	30,294
15. Avail. Reserve (14-2)	4,913	4,316	6,223	4,978	6,057	4,509	6,303	4,588	5,576	3,503
16. Avail. Reserve (%) (15/2) x 100	22.5	18.1	27.8	20.2	26.4	17.9	26.8	17.7	23.1	13.1
17. Other Unavailable 2/	1,086	1,358	1,146	1,413	1,150	1,417	1,184	1,457	1,179	1,450
18. Actual Capability Avail. (14-17)	25,632	26,851	27,498	28,151	27,840	28,225	28,622	28,992	28,517	28,844
19. Actual Reserves (18-2)	3,827	2,958	5,078	3,565	4,908	3,092	5,120	3,131	4,397	2,053
20. Actual Reserve (%) (19/2) x 100	17.6	12.4	22.6	14.5	21.4	12.3	21.8	12.1	18.2	7.7

1/ Assumes no new unit delays.

2/ Maintenance outages, other unavailable capacity and forced outages were derived from historic data and are actual average values which occurred between 1977 and 1980 at the time of the respective summer and winter seasonal peak demands expressed in constant percentage of planned capability.

Based on SERC ERA-411 Report dated April 1, 1981.

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Table 7.A.6

Installed Net Generating Capability By Type of Fuel-Mw
Florida Region
Summer Capability - 1981-90

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Other	Planned Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage		
1981	2830	2687	13875	4655	172	184	30	0	36	0	60	24529
% Total	11.54	10.95	56.57	18.98	0.70	0.75	0.12	0.0	0.15	0.0	0.24	100.00
1982	2866	3046	14101	4655	172	184	30	0	36	0	60	25150
% Total	11.40	12.11	56.07	18.51	0.68	0.73	0.12	0.0	0.14	0.0	0.24	100.00
1983	3615	4286	14011	4629	190	184	30	0	36	0	60	27041
% Total	13.37	15.85	51.81	17.12	0.70	0.68	0.11	0.0	0.13	0.0	0.22	100.00
1984	3635	4286	13997	4629	210	177	30	0	47	0	60	27071
% Total	13.43	15.83	51.70	17.10	0.78	0.65	0.11	0.0	0.17	0.0	0.22	100.00
1985	3750	5943	13997	4629	210	177	30	0	47	0	60	28843
% Total	13.00	20.60	48.53	16.05	0.73	0.61	0.10	0.0	0.16	0.0	0.21	100.00
1986	3750	6493	13997	4629	210	140	30	0	47	0	60	29356
% Total	12.77	22.12	47.68	15.77	0.72	0.48	0.10	0.0	0.16	0.0	0.20	100.00
1987	3750	8098	13997	4629	210	140	30	0	47	0	60	30961
% Total	12.11	26.16	45.21	14.95	0.68	0.45	0.10	0.0	0.15	0.0	0.19	100.00
1988	3865	8098	13997	4629	210	133	30	0	47	0	60	31069
% Total	12.44	26.06	45.05	14.90	0.68	0.43	0.10	0.0	0.15	0.0	0.19	100.00
1989	3865	9198	13955	4490	210	133	30	0	47	0	60	31988
% Total	12.08	28.75	43.63	14.04	0.66	0.42	0.09	0.0	0.15	0.0	0.19	100.00
1990	3865	9198	13895	4432	205	133	30	0	47	0	60	31865
% Total	12.13	28.87	43.61	13.91	0.64	0.42	0.09	0.0	0.15	0.0	0.19	100.00

This table is based on the SERC April 1, 1981 ERA-411 Report.

Table 7.A.7

Installed Net Generating Capability By Type of Fuel-Mw
Florida Region
Winter Capability - 1981-90

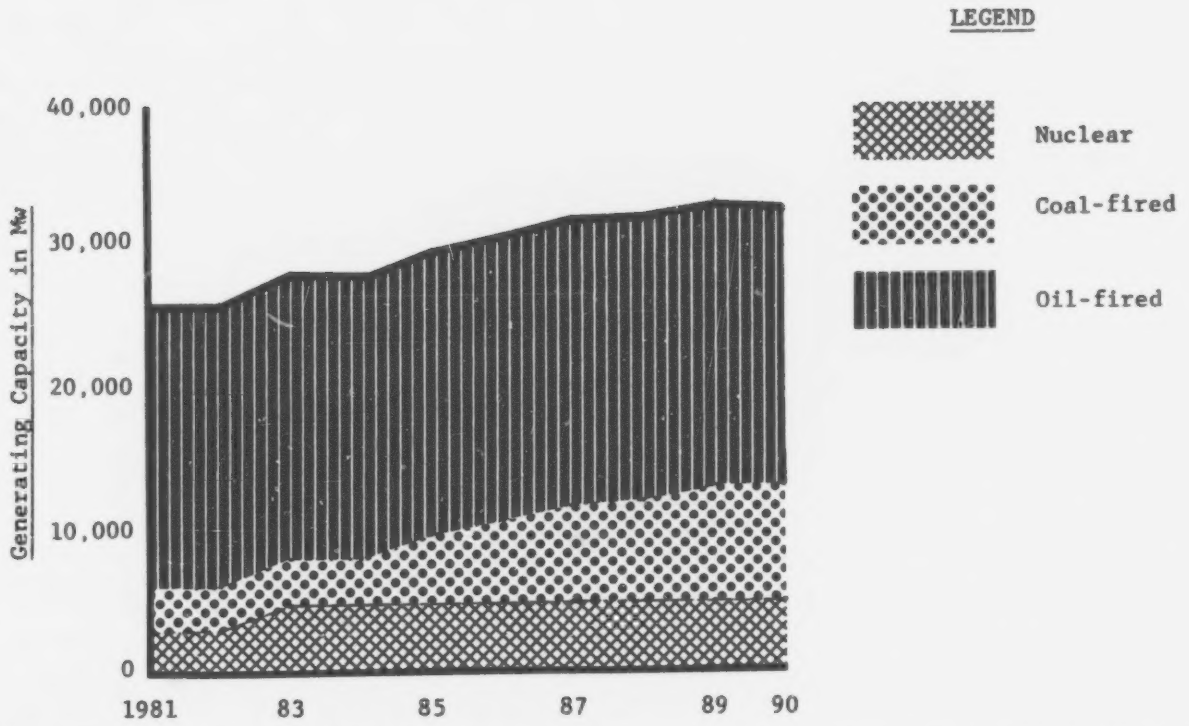
	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Other	Planned Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage		
1981	2967	3022	14080	5495	173	190	35	0	36	0	60	26058
% Total	11.39	11.60	54.03	21.09	0.66	0.73	0.13	0.0	0.14	0.0	0.23	100.00
1982	2987	3047	14209	5463	172	190	35	0	36	0	60	26190
% Total	11.41	11.63	54.22	20.86	0.66	0.73	0.13	0.0	0.14	0.0	0.23	100.00
1983	3754	4287	14200	5463	204	183	35	0	47	0	60	28233
% Total	13.30	15.18	50.30	19.35	0.72	0.65	0.12	0.0	0.17	0.0	0.21	100.00
1984	3754	4287	14184	5463	204	183	35	0	47	0	60	28217
% Total	13.30	15.19	50.27	19.36	0.72	0.65	0.12	0.0	0.17	0.0	0.21	100.00
1985	3869	5944	14184	5463	204	175	35	0	47	0	60	29981
% Total	12.90	19.83	47.31	18.22	0.68	0.58	0.12	0.0	0.16	0.0	0.20	100.00
1986	3869	6849	14184	5463	204	143	35	0	47	0	60	30854
% Total	12.54	22.20	45.97	17.71	0.66	0.46	0.11	0.0	0.15	0.0	0.19	100.00
1987	3869	8109	14184	5463	204	143	35	0	47	0	60	32114
% Total	12.05	25.25	44.17	17.01	0.64	0.45	0.11	0.0	0.15	0.0	0.19	100.00
1988	3984	8109	14166	5463	204	135	35	0	47	0	60	32203
% Total	12.37	25.18	43.99	16.96	0.63	0.42	0.11	0.0	0.15	0.0	0.19	100.00
1989	3984	9219	14141	5298	204	135	35	0	47	0	60	33123
% Total	12.03	27.83	42.69	15.99	0.62	0.41	0.11	0.0	0.14	0.0	0.18	100.00
1990	3984	9219	14054	5229	183	135	35	0	47	0	60	32946
% Total	12.09	27.98	42.66	15.87	0.56	0.41	0.11	0.0	0.14	0.0	0.18	100.00

This table is based on the SERC April 1, 1981 ERA-411 Report.

Figure 7.A.2

Florida Installed Capacity By Fuel Types

1981-1990

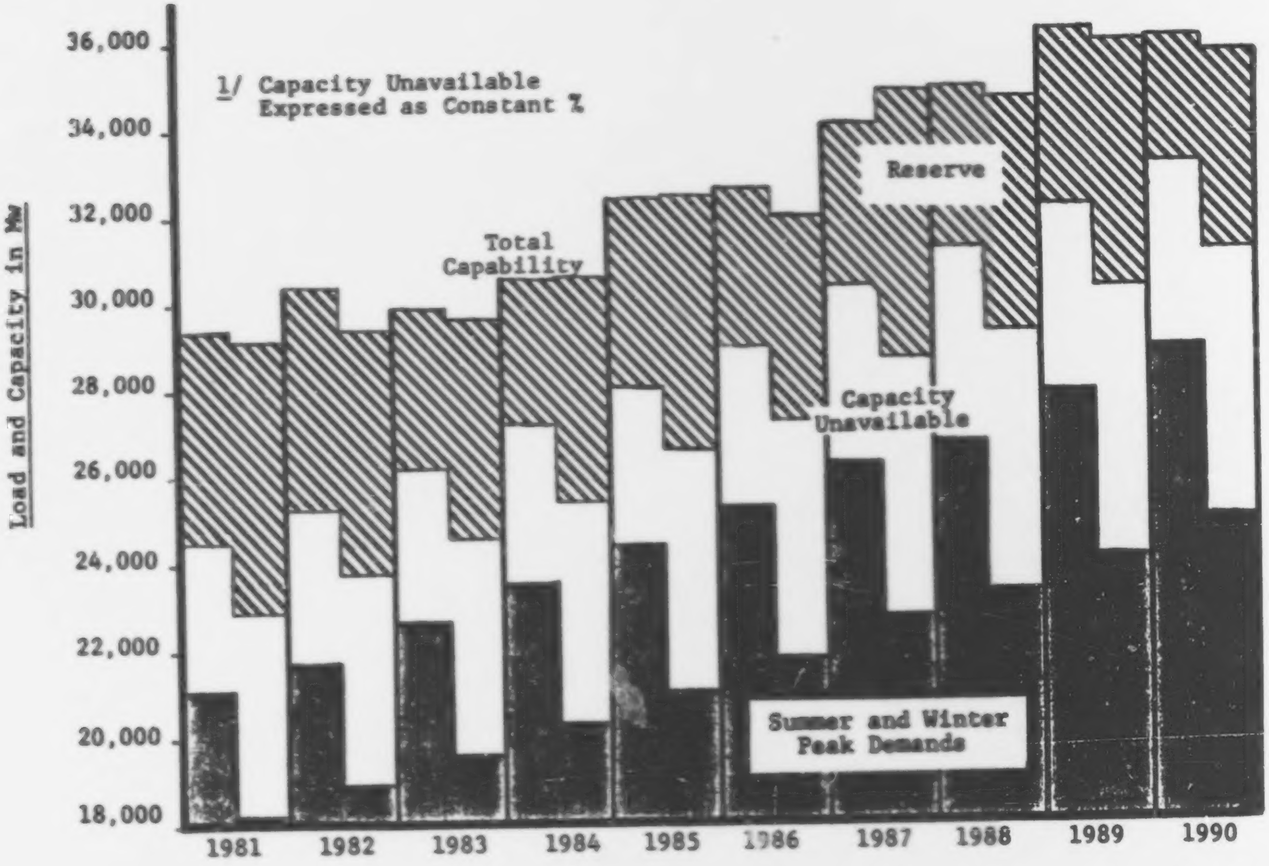


1/ Capacity based on winter rating of units as reported in Item 2 of the SERC April 1, 1981 ERA-411 Report.

Figure 7.B.1

Southern Generation Reserve Outlook 1/

1981-1990



Based on SERC ERA-411 Report dated April 1, 1981.

Table 7.B.4

Future Generating Capability (Mw) and Reserves (Mw and Percent) - 1981-1985

Southern Companies Region

Mw or Percent	1981 Summer	1981 Winter	1982 Summer	1982 Winter	1983 Summer	1983 Winter	1984 Summer	1984 Winter	1985 Summer	1985 Winter
1. Planned Capability 1/	29,286	29,293	30,219	30,226	30,336	30,329	31,130	31,249	33,141	33,282
2. Peak Demand	21,101	18,136	21,742	18,902	22,689	19,657	23,532	20,328	24,401	21,043
3. Planned Reserve (1-2)	8,185	11,157	8,477	11,324	7,647	10,672	7,598	10,921	8,740	12,239
4. Planned Reserve (%) (3/2) x 100	38.8	61.5	39.0	59.9	33.7	54.3	32.3	53.7	35.8	58.2
5. Net Transactions	140	(140)	140	(790)	(510)	(690)	(610)	(690)	(725)	(805)
6. Total Capability (1+5)	29,426	29,153	30,359	29,436	29,826	29,639	30,520	30,559	32,416	32,477
7. Total Reserve (6-2)	8,325	11,017	8,617	10,534	7,137	9,982	6,988	10,231	8,015	11,434
8. Total Reserve (%) (7/2) x 100	39.5	60.7	39.6	55.7	31.5	50.8	29.7	50.3	32.8	54.3
9. Scheduled Maint. 2/	527	2,519	544	2,599	546	2,608	560	2,687	597	2,862
10. Capability after Main. (6-9)	28,899	26,634	29,815	26,837	29,280	27,031	29,960	27,872	31,820	29,615
11. Reserve after Maint. (10-2)	7,798	8,498	8,073	7,935	6,591	7,373	6,428	7,544	7,419	8,572
12. Reserv.aft.Maint.(%) (11/2) x 100	37.0	46.9	37.1	42.0	29.0	37.5	27.3	37.1	30.4	40.7
13. Full Forced Outage (F.O.) 2/	1,816	1,582	1,874	1,632	1,881	1,638	1,930	1,687	2,055	1,797
14. Cap.aft. F.O. (10-13)	27,083	25,052	27,941	25,204	27,399	25,393	28,030	26,184	29,765	27,818
15. Avail. Reserve (14-2)	5,982	6,916	6,200	6,302	4,710	5,736	4,498	5,856	5,364	6,775
16. Avail. Reserve (%) (15/2) x 100	28.3	38.1	28.5	33.3	20.8	29.2	19.1	28.8	22.0	32.2
17. Other Unavailable 2/	1,054	703	1,088	725	1,092	728	1,121	750	1,193	799
18. Actual Capability Avail. (14-17)	26,029	24,349	26,853	24,479	26,307	24,665	26,909	25,434	28,572	27,019
19. Actual Reserve (18-2)	4,928	6,213	5,112	5,576	3,618	5,008	3,376	5,106	4,171	5,956
20. Actual Reserve (%) (19/2) x 100	23.4	34.3	23.5	29.5	15.9	25.5	14.4	25.1	17.1	28.4

1/ Assumes no new unit delays.

2/ Maintenance outages, other unavailable capacity and forced outages were derived from historic data and are actual average values which occurred between 1977 and 1980 at the time of the respective summer and winter seasonal peak demands expressed in constant percent of planned capability.

Based on SERC ERA-411 Report dated April 1, 1981.

Table 7.B.5

Future Generating Capability (Mw) and Reserves (Mw and Percent) - 1986-1990

Southern Companies Subregion

	1986		1987		1988		1989		1990	
Mw or Percent	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	33,300	33,209	35,283	36,334	36,414	36,336	37,814	37,595	37,590	37,337
2. Peak Demand	25,251	21,774	26,256	22,721	26,970	23,314	27,866	24,102	28,854	24,932
3. Planned Reserve (1-2)	8,049	11,435	9,027	13,613	9,444	13,022	9,948	13,493	8,736	12,405
4. Planned Reserve (%) (3/2) x 100	31.9	52.5	34.4	59.9	35.0	55.9	35.7	56.0	30.3	49.8
5. Net Transactions	(725)	(1,305)	(1,225)	(1,555)	(1,590)	(1,670)	(1,590)	(1,670)	(1,590)	(1,670)
6. Total Capability (1+5)	32,575	31,904	34,058	34,779	34,824	34,666	36,224	35,925	36,000	35,667
7. Total Reserve (6-2)	7,324	10,130	7,802	12,058	7,854	11,352	8,358	11,823	7,146	10,735
8. Total Reserve (%) (7/2) x 100	29.0	46.5	29.7	53.1	29.1	48.7	30.0	49.1	24.8	43.1
9. Scheduled Maint. 2/	599	2,856	635	3,125	656	3,125	681	3,233	677	3,211
10. Capability after Main. (6-9)	31,976	29,048	33,423	31,654	34,169	31,541	35,543	32,691	35,323	32,456
11. Reserve after Maint. (10-2)	6,725	7,274	7,167	8,933	7,199	8,227	7,677	8,590	6,469	7,524
12. Reserv.aft.Maint.(%) (11/2) x 100	26.6	33.4	27.3	39.3	26.7	35.3	27.6	35.6	22.4	30.2
13. Full Forced Outage (F.O.) 2/	2,065	1,793	2,188	1,962	2,258	1,962	2,345	2,030	2,331	2,016
14. Cap.aft. F.O. (10-13)	29,911	27,254	31,235	29,692	31,911	29,579	33,198	30,662	32,993	30,440
15. Avail. Reserve (14-2)	4,660	5,481	4,979	6,971	4,941	6,265	5,333	6,560	4,139	5,508
16. Avail. Reserve (%) (15/2) x 100	18.5	25.2	19.0	30.7	18.3	26.9	19.1	27.2	14.3	22.1
17. Other Unavailable 2/	1,199	797	1,270	872	1,311	872	1,361	902	1,353	896
18. Actual Capability Avail. (14-17)	28,712	26,450	29,965	28,820	30,600	28,707	31,838	29,759	31,640	29,544
19. Actual Reserve (18-2)	3,461	4,684	3,709	6,099	3,630	5,393	3,972	5,651	2,786	4,612
20. Actual Reserve (%) (19/2) x 100	13.7	21.5	14.1	26.8	13.5	23.1	14.3	23.5	9.7	18.5

1/ Assumes no new unit delays.

2/ Maintenance outages, other unavailable capacity and forced outages were derived from historic data and are actual average values which occurred between 1977 and 1980 at the time of the respective summer and winter seasonal peak demands expressed in constant percent of planned capability.

Based on SERC ERA-411 Report dated April 1, 1981.

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Table 7.B.6

Installed Net Generation Capability By Type of Fuel-Mw
Southern Companies Region

Summer

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Other	Planned Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage		
1981	3,152	19,654	1,388	1,243	5	81	51	0	3,225	487	0	29,286
% Total	10.8	67.1	4.7	4.2	.02	.3	.2	0	11.0	1.7	0	100.0
1982	3,277	20,462	1,388	1,243	5	81	51	0	3,225	487	0	30,219
% Total	10.8	67.7	4.6	4.1	.02	.3	.2	0	10.7	1.6	0	100.0
1983	3,277	20,462	1,388	1,243	5	81	51	0	3,342	487	0	30,336
% Total	10.8	67.5	4.6	4.1	.02	.3	.2	0	11.0	1.6	0	100.0
1984	3,277	21,270	1,334	1,243	5	81	51	0	3,382	487	0	31,130
% Total	10.5	68.3	4.3	4.0	.02	.3	.2	0	10.9	1.6	0	100.0
1985	4,427	21,924	1,334	1,209	5	81	51	0	3,623	487	0	33,141
% Total	13.4	66.2	4.0	3.6	.02	.2	.2	0	10.9	1.5	0	100.0
1986	4,427	21,924	1,310	1,162	5	81	51	0	3,778	562	0	33,300
% Total	13.3	65.8	3.9	3.5	.02	.2	.2	0	11.3	1.7	0	100.0
1987	4,427	23,250	1,248	1,131	5	81	51	0	3,778	1,312	0	35,283
% Total	12.5	65.9	3.5	3.2	.01	.2	.1	0	10.7	3.7	0	100.0
1988	5,702	23,207	1,222	1,086	5	81	21	0	3,778	1,312	0	36,414
% Total	15.7	63.7	3.4	3.0	.01	.2	.06	0	10.4	3.6	0	100.0
1989	5,702	24,540	1,222	1,086	5	81	21	0	3,845	1,312	0	37,814
% Total	15.1	64.9	3.2	2.9	.01	.2	.06	0	10.2	3.5	0	100.0
1990	5,702	24,446	1,198	1,061	5	0	21	0	3,845	1,312	0	37,590
% Total	15.2	65.0	3.2	2.8	.01	0	.06	0	10.2	3.5	0	100.0

This table is based on the SERC April 1, 1981 ERA-411 Report.

Table 7.B.7

Installed Net Generation Capability By Type of Fuel-Mw

Southern Companies Region

Winter

			Oil			Natural Gas			Hydro			
	Nuclear Steam	Coal Steam	Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage	Other	Planned Capability
1981	3,152	19,654	1,388	1,381	5	81	52	0	3,090	490	0	29,293
% Total	10.8	67.1	4.7	4.7	.02	.3	.2	0	10.5	1.7	0	100.0
1982	3,277	20,462	1,388	1,381	5	81	52	0	3,090	490	0	30,226
% Total	10.8	67.7	4.6	4.6	.02	.3	.2	0	10.2	1.6	0	100.0
1983	3,277	20,462	1,334	1,381	5	81	52	0	3,247	490	0	30,329
% Total	10.8	67.5	4.4	4.6	.02	.3	.2	0	10.7	1.6	0	100.0
1984	3,277	21,270	1,334	1,343	5	81	52	0	3,397	490	0	31,249
% Total	10.5	68.1	4.3	4.3	.02	.3	.2	0	10.9	1.6	0	100.0
1985	4,427	21,924	1,334	1,326	5	81	52	0	3,643	490	0	33,282
% Total	13.3	65.9	4.0	4.0	.02	.2	.1	0	10.9	1.5	0	100.0
1986	4,427	21,822	1,248	1,291	5	81	52	0	3,643	640	0	33,209
% Total	13.3	65.7	3.8	3.9	.02	.2	.2	0	11.0	1.9	0	100.0
1987	5,577	23,207	1,248	1,206	5	81	52	0	3,643	1,315	0	31,334
% Total	15.3	63.7	3.4	3.3	.01	.2	.1	0	10.0	3.6	0	100.0
1988	5,702	23,078	1,222	1,206	5	81	17	0	3,710	1,315	0	36,336
% Total	15.7	65.3	3.4	3.3	.01	.2	.05	0	10.2	3.6	0	100.0
1989	5,702	24,446	1,222	1,178	5	0	17	0	3,710	1,315	0	37,595
% Total	15.2	65.0	3.3	3.1	.01	0	.05	0	9.9	3.5	0	100.0
1990	5,702	24,446	1,068	1,074	5	0	17	0	3,710	1,315	0	37,337
% Total	15.3	65.5	2.9	2.9	.01	0	.05	0	9.9	3.5	0	100.0

This table is based on The SERC April 1, 1981 ERA-411 Report.

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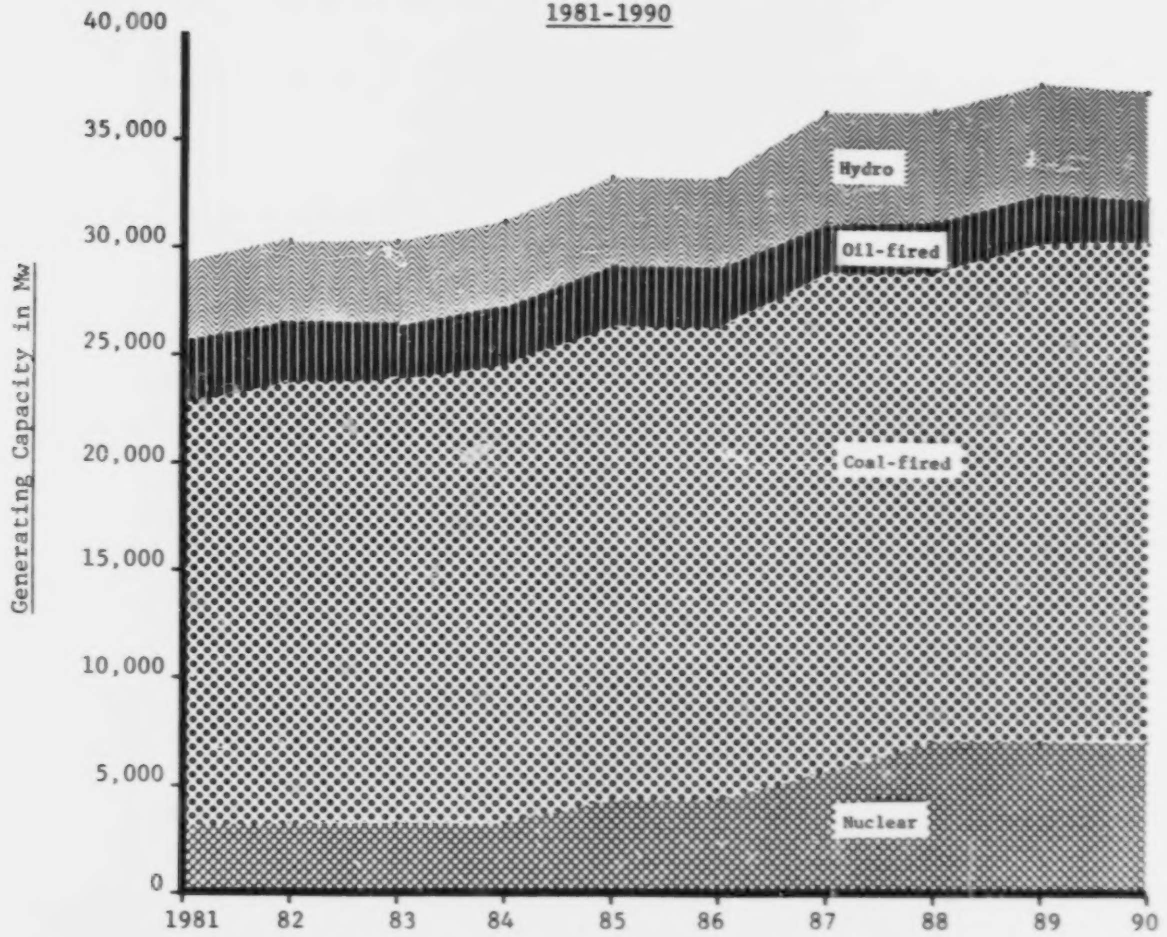
Figure 7.B.2

Southern Installed Capacity by Fuel Types[1]

1981-1990

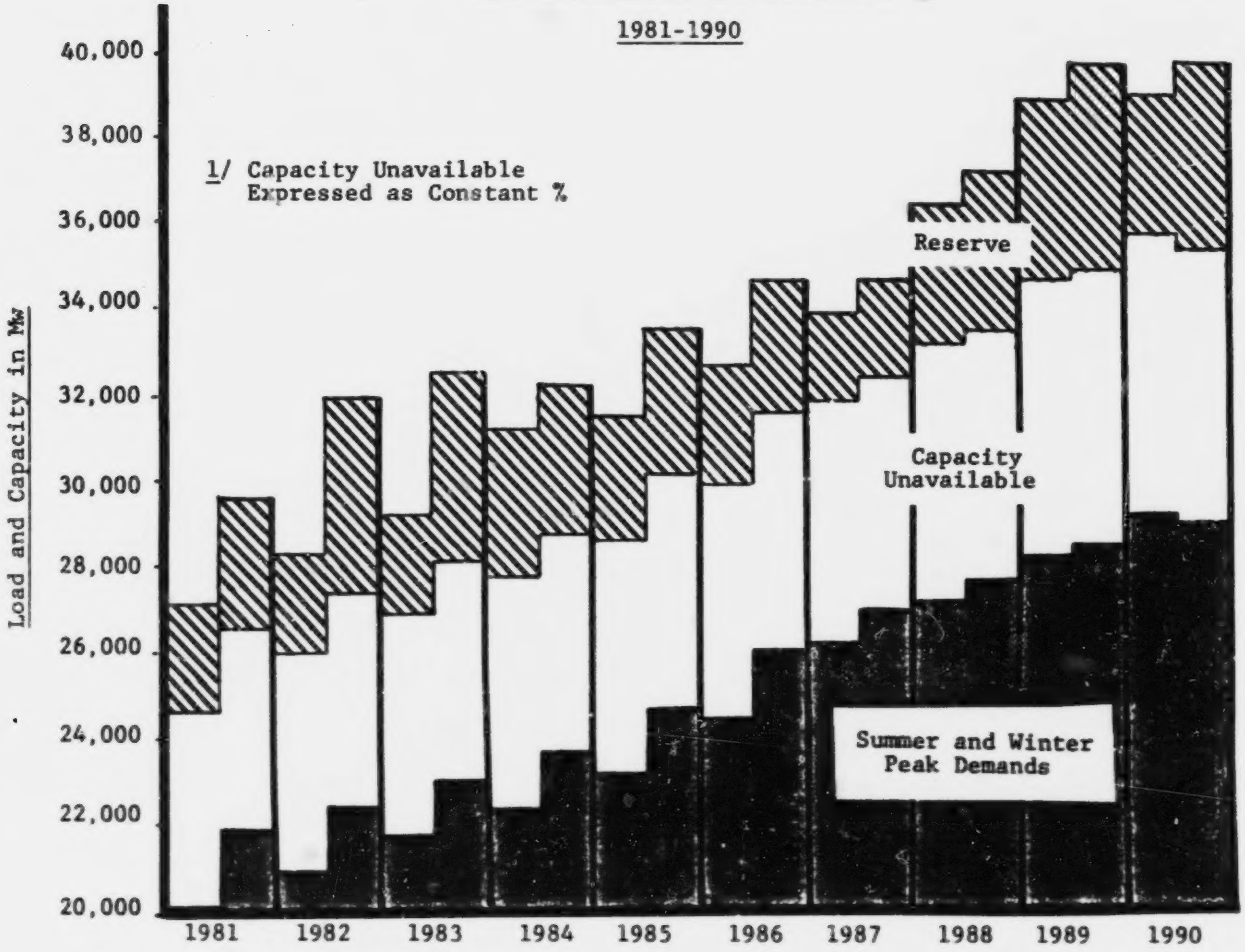


[1] Capacity based on winter rating of units as reported in Item 2 of the SERC April 1, 1981 ERA-411 Report.

Figure 7.C.1

TVA Generation Reserve Outlook 1/

1981-1990



Based on SERC ERA-411 Report dated April 1, 1981.

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Table 7.C.4

Future Generating Capability (Mw) and Reserves (Mw and Percent) - 1981-1985

TVA Region

Mw or Percent:	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	28,232	28,457	29,380	30,782	30,557	31,959	31,734	31,959	31,734	33,172
2. Peak Demand	20,016	21,993	21,199	22,477	21,756	22,965	22,341	23,672	23,212	24,617
3. Planned Reserve (1-2)	8,716	6,464	8,181	8,305	8,801	8,994	9,393	8,287	8,522	8,555
4. Planned Reserve (%) (3/2) x 100	41.0	29.4	38.6	36.9	40.5	39.2	42.0	35.0	36.7	34.8
5. Net Transactions	(1,100)	1,100	(1,100)	1,100	(1,100)	500	(500)	275	(275)	275
6. Total Capability (1+5)	27,132	29,557	28,280	31,882	29,457	32,459	31,234	32,234	31,459	33,447
7. Total Reserve (6-2)	7,116	7,564	7,081	9,405	7,701	9,494	8,893	8,562	8,247	8,830
8. Total Reserve (%) (7/2) x 100	35.6	34.4	33.4	41.8	35.4	41.3	39.8	36.2	35.5	35.9
9. Scheduled Maint. 2/	395	768	411	831	428	863	444	863	444	896
10. Capability after Main. (6-9)	26,737	28,789	27,869	31,051	29,029	31,596	30,790	31,371	31,015	32,551
11. Reserve after Maint. (10-2)	6,721	6,796	6,670	8,574	7,273	8,631	8,449	7,699	7,803	7,934
12. Reserv.aft.Maint.(%) (11/2) x 100	33.6	30.9	32.5	38.1	33.4	37.6	37.8	32.5	33.6	32.2
13. Full Forced Outage (F.O.) 2/	2,908	2,362	3,026	2,555	3,147	2,653	3,269	2,653	3,269	2,753
14. Cap.aft. F.O. (10-13)	23,829	26,427	24,843	28,496	25,882	28,944	27,521	28,719	27,746	29,798
15. Avail. Reserve (14-2)	3,813	4,434	3,644	3,019	4,126	5,979	5,180	5,047	4,534	5,181
16. Avail. Reserve (%) (15/2) x 100	19.0	20.2	17.2	26.8	19.0	26.0	23.2	21.3	19.5	21.0
17. Other Unavailable 2/	1,327	1,423	1,381	1,539	1,436	1,598	1,491	1,598	1,492	1,659
18. Actual Capability Avail. (14-17)	22,502	25,004	23,462	26,957	24,446	27,346	26,030	27,121	26,255	28,139
19. Actual Reserve (18-2)	2,486	3,011	2,263	4,480	2,690	4,381	3,689	3,449	3,043	3,523
20. Actual Reserve (%) (19/2) x 100	12.4	13.7	10.7	19.9	12.4	19.1	16.5	14.6	13.1	14.3

1/ Assumes no new unit delays.

2/ Maintenance outages, other unavailable capacity and forced outages were derived from historic data and are actual average values which occurred between 1977 and 1980 at the time of the respective summer and winter seasonal peak demands expressed in constant percent of planned capability.

Based on SERC ERA-411 Report dated April 1, 1981.

Table 7.C.5

Future Generating Capability (Mw) and Reserves (Mw and Percent) - 1986-1990

TVA Region

Mw or Percent	1986		1987		1988		1989		1990	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	32,947	34,385	34,160	34,385	36,678	36,903	39,144	39,369	39,144	39,369
2. Peak Demand	24,449	26,046	26,153	26,826	27,119	27,592	28,109	28,401	29,181	28,888
3. Planned Reserve (1-2)	8,498	8,339	8,002	7,559	9,559	9,311	11,035	10,968	9,963	10,481
4. Planned Reserve (%) (3/2) x 100	34.8	32.0	30.6	28.2	35.2	33.7	39.3	38.6	34.1	36.3
5. Net Transactions	(275)	275	(275)	275	(275)	275	(275)	275	(275)	275
6. Total Capability (1+5)	32,672	34,660	33,885	34,660	36,403	37,178	38,869	39,644	38,869	39,644
7. Total Reserve (6-2)	8,223	8,614	7,727	7,834	9,284	9,586	10,760	11,243	9,688	10,756
8. Total Reserve (%) (7/2) x 100	33.6	33.1	29.5	29.2	34.2	34.7	38.3	39.6	33.2	37.2
9. Scheduled Maint. 2/	461	928	478	928	514	996	548	1,063	548	1,063
10. Capability after Main. (6-9)	32,211	33,732	33,407	33,732	35,890	36,182	38,321	38,581	38,321	38,581
11. Reserve after Maint. (10-2)	7,762	7,686	7,249	6,906	8,771	8,590	10,212	10,180	9,140	9,693
12. Reserv.aft.Maint.(%) (11/2) x 100	31.7	29.5	27.7	25.7	32.3	31.1	36.3	35.8	31.3	33.6
13. Full Forced Outage (F.O.) 2/	3,394	2,884	3,519	2,854	3,778	3,063	4,032	3,268	4,032	3,268
14. Cap.aft. F.O. (10-13)	28,817	30,877	29,888	30,878	32,112	33,119	34,289	35,313	34,289	
15. Avail. Reserve (14-2)	4,368	4,831	3,730	4,051	4,993	5,527	6,180	6,912	5,108	6,425
16. Avail. Reserve (%) (15/2) x 100	17.9	18.6	14.3	15.1	18.4	20.0	22.0	24.3	17.5	22.2
17. Other Unavailable 2/	1,549	1,719	1,606	1,719	1,724	1,845	1,840	1,968	1,840	1,968
18. Actual Capability Avail. (14-17)	27,269	29,158	28,283	29,158	30,387	31,274	32,449	33,345	32,449	33,345
19. Actual Reserve (18-2)	2,820	3,112	2,125	2,332	3,269	3,682	4,340	4,944	3,268	4,457
20. Actual Reserve (%) (19/2) x 100	11.5	11.9	8.1	8.7	12.1	13.3	15.4	17.4	11.2	15.4

1/ Assumes no new unit delays.

2/ Maintenance outages, other unavailable capacity and forced outages were derived from historic data and are actual average values which occurred between 1977 and 1980 at the time of the respective summer and winter seasonal peak demands expressed in constant percent of planned capability.

Based on SERC ERA-411 Report dated April 1, 1981.

Table 7.C.6

Installed Net Generation Capability By Type of Fuel-Mw
TVA Region

Summer

	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Other	Planned Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage		
1981	4,343	16,210	0	2,066	0	0	0	0	4,306	1,300	0	28,232
% Total	15.4	57.4	0	7.3	0	0	0	0	15.3	4.6	0	100.0
1982	5,491	16,210	0	2,066	0	0	0	0	4,306	1,300	0	29,380
% Total	18.9	55.2	0	7.0	0	0	0	0	14.7	4.4	0	100.0
1983	6,668	16,210	0	2,066	0	0	0	0	4,306	1,300	0	30,557
% Total	21.8	53.0	0	6.8	0	0	0	0	14.1	4.3	0	100.0
1984	7,845	16,210	0	2,066	0	0	0	0	4,306	1,300	0	31,734
% Total	24.7	51.1	0	6.5	0	0	0	0	13.6	4.1	0	100.0
1985	7,845	16,210	0	2,066	0	0	0	0	4,306	1,300	0	31,734
% Total	24.7	51.1	0	6.5	0	0	0	0	13.6	4.1	0	100.0
1986	9,058	16,210	0	2,066	0	0	0	0	4,306	1,300	0	32,947
% Total	27.5	49.2	0	6.3	0	0	0	0	13.1	3.9	0	100.0
1987	10,271	16,210	0	2,066	0	0	0	0	4,306	1,300	0	34,160
% Total	30.1	47.5	0	6.0	0	0	0	0	12.6	3.8	0	100.0
1988	12,789	16,210	0	2,066	0	0	0	0	4,706	1,300	0	36,678
% Total	34.9	44.2	0	5.6	0	0	0	0	11.7	3.5	0	100.0
1989	15,255	16,210	0	2,066	0	0	0	0	4,306	1,300	0	39,144
% Total	39.0	41.4	0	5.3	0	0	0	0	11.0	3.3	0	100.0
1990	15,255	16,210	0	2,066	0	0	0	0	4,306	1,300	0	39,144
% Total	39.0	41.4	0	5.3	0	0	0	0	11.0	3.3	0	100.0

This table is based on the SERC April 1, 1981 ERA-411 Report.

Table 7.C.7

Installed Net Generation Capability By Type of Fuel-Mw
TVA Companies Region

Winter

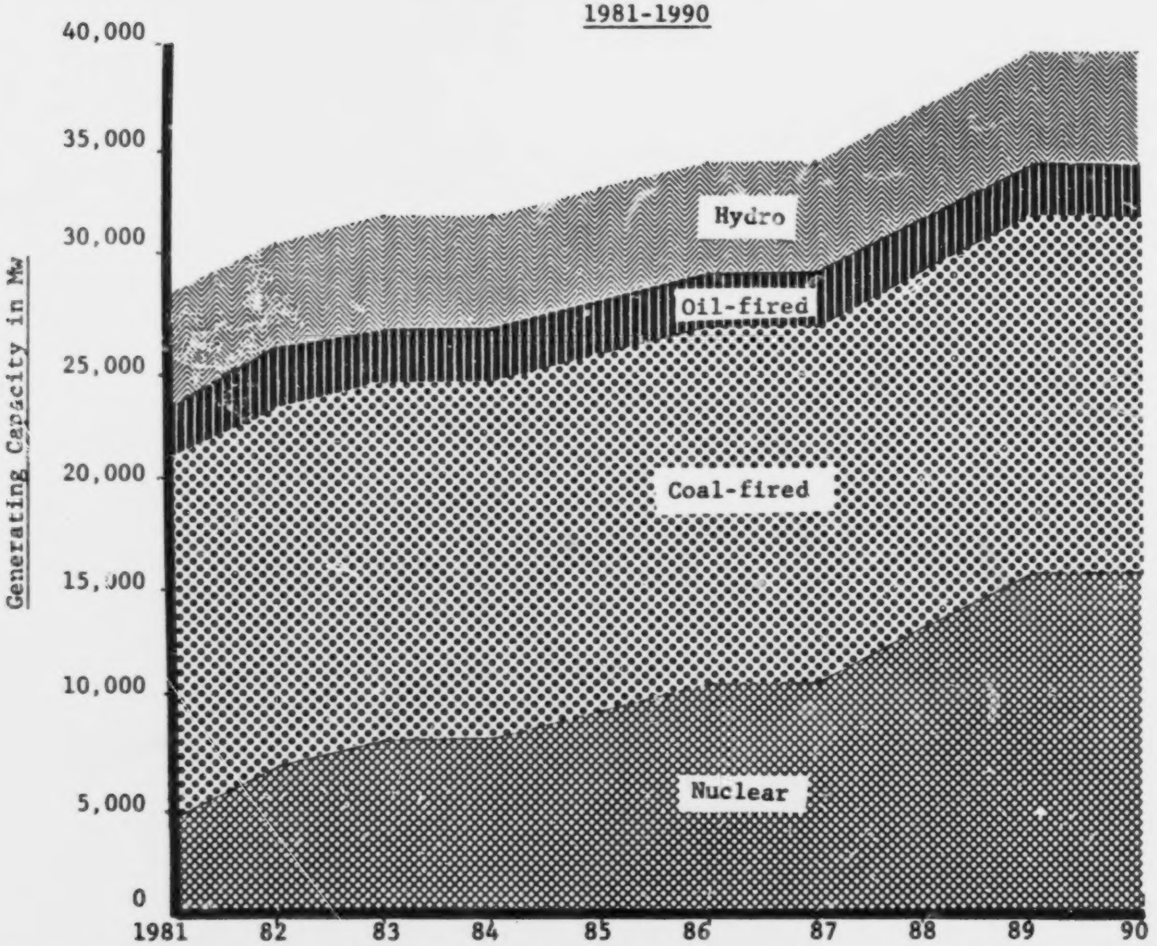
	Nuclear Steam	Coal Steam	Oil			Natural Gas			Hydro		Other	Planned Capability
			Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage		
1981	4,343	16,497	0	2,432	0	0	0	0	3,885	1,300	0	28,457
% Total	15.3	58.0	0	8.5	0	0	0	0	13.7	4.6	0	100.0
1982	6,668	16,497	0	2,432	0	0	0	0	3,885	1,300	0	30,782
% Total	21.7	53.4	0	7.9	0	0	0	0	12.6	4.2	0	100.0
1983	7,845	16,497	0	2,432	0	0	0	0	3,885	1,300	0	31,959
% Total	24.5	51.6	0	7.6	0	0	0	0	12.2	4.1	0	100.0
1984	7,845	16,497	0	2,432	0	0	0	0	3,885	1,300	0	31,959
% Total	24.5	51.6	0	7.6	0	0	0	0	12.2	4.1	0	100.0
1985	9,058	16,497	0	2,432	0	0	0	0	3,885	1,300	0	33,172
% Total	27.3	49.7	0	7.3	0	0	0	0	11.7	3.9	0	100.0
1986	10,271	16,497	0	2,432	0	0	0	0	3,885	1,300	0	34,385
% Total	29.9	48.0	0	7.1	0	0	0	0	11.3	3.8	0	100.0
1987	10,271	16,497	0	2,432	0	0	0	0	3,885	1,300	0	34,385
% Total	29.9	48.0	0	7.1	0	0	0	0	11.3	3.8	0	100.0
1988	12,789	16,497	0	2,432	0	0	0	0	3,885	1,300	0	36,903
% Total	34.7	44.7	0	6.6	0	0	0	0	10.5	3.5	0	100.0
1989	15,255	16,497	0	2,432	0	0	0	0	3,885	1,300	0	39,369
% Total	38.7	41.9	0	6.2	0	0	0	0	9.9	3.3	0	100.0
1990	15,255	16,497	0	2,432	0	0	0	0	3,885	1,300	0	39,369
% Total	38.7	41.9	0	6.2	0	0	0	0	9.9	3.3	0	100.0

This table is based on the SERC April 1, 1981 ERA-411 Report.

Figure 7.C.2

TVA Installed Capacity by Fuel Types [1]

1981-1990

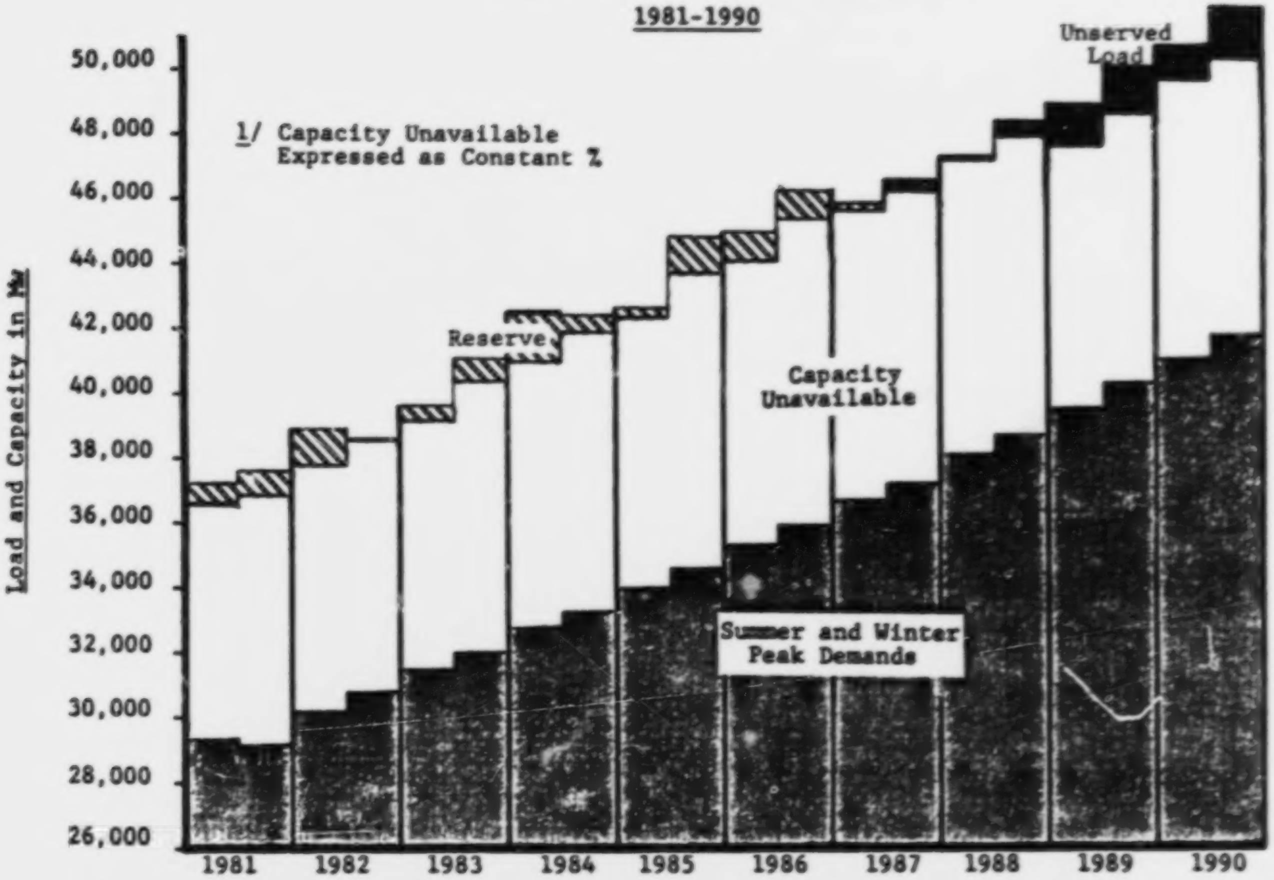


[1] Capacity based on winter rating of units as reported in Item 2 of the SERC April 1, 1981 ERA-411 Report.

Figure 7.D.1

VACAR Generation Reserve Outlook 1/

1981-1990



Based on SERC ERA-411 Report dated April 1, 1981.

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Table 7.D.4

Future Generating Capability (Mw) and Reserves (Mw and Percent) - 1981-1985

VACAR Region

Mw or Percent	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	36,333	37,911	38,526	38,873	39,289	41,347	42,188	42,642	42,338	45,077
2. Peak Demand	29,302	29,150	30,232	30,700	31,453	31,994	32,715	33,266	33,961	34,556
3. Planned Reserve (1-2)	7,032	8,761	8,294	8,173	7,836	9,353	9,473	9,376	8,377	10,521
4. Planned Reserve (%) (3/2) x 100	24.0	30.1	27.4	26.6	24.9	29.2	29.0	28.2	24.7	30.4
5. Net Transactions	900	(300)	300	(300)	300	(300)	300	(300)	300	(300)
6. Total Capability 1+5)	37,233	37,611	38,826	38,573	39,589	41,047	42,488	42,342	42,638	44,777
7. Total Reserve (6-2)	7,931	8,461	8,594	7,873	8,136	9,053	9,773	9,076	8,677	10,221
8. Total Reserve (%) (7/2) x 100	27.1	29.0	28.4	25.6	25.9	28.3	29.9	27.3	25.5	29.6
9. Scheduled Maint. 2/	2,144	2,426	2,273	2,488	2,318	2,646	2,489	2,729	2,498	2,885
10. Capability after Main. (6-9)	35,089	35,185	36,553	36,085	37,271	38,401	39,999	39,613	40,140	41,892
11. Reserve after Maint. (10-2)	5,787	6,035	6,321	5,385	5,818	6,407	7,284	6,347	6,179	7,336
12. Reserv.aft.Maint.(%) (11/2) x 100	19.8	20.7	20.9	17.5	18.5	20.0	22.3	19.1	18.2	21.2
13. Full Forced Outage (F.O.) 2/	2,107	2,047	2,235	2,099	2,279	2,233	2,447	2,303	2,456	2,434
14. Cap.aft. F.O. (10-13)	32,982	33,138	34,319	33,986	34,992	36,168	37,552	37,310	37,684	39,458
15. Avail. Reserve (14-2)	3,680	3,988	4,087	3,286	3,539	4,174	4,837	4,044	3,723	4,902
16. Avail. Reserve (%) (15/2) x 100	12.6	13.7	13.5	10.7	11.3	13.0	14.8	12.2	11.0	14.2
17. Other Unavailable 2/	2,834	3,185	3,005	3,265	3,065	3,473	3,291	3,582	3,302	3,787
18. Actual Capability Avail. (14-17)	30,148	29,953	31,313	30,721	31,928	32,695	34,261	33,728	34,382	35,671
19. Actual Reserve (18-2)	846	803	1,081	21	475	701	1,546	462	421	1,115
20. Actual Reserve (%) (19-2) x 100	2.9	2.8	3.6	0.1	1.5	2.2	4.7	1.4	1.2	3.2

1/ Assumes no new unit delays.

2/ Maintenance outages, other unavailable capacity and forced outages were derived from historic data and are actual average values which occurred between 1977 and 1980 at the time of the respective summer and winter seasonal peak demands expressed in constant percent of planned capability.

Based on SERC ERA-411 Report dated April 1, 1981.

Table 7.D.5

Future Generating Capability (Mw) and Reserves (Mw and Percent) - 1986-1990

VACAR Region

	1986		1987		1988		1989		1990	
Mw or Percent	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	44,848	46,109	45,805	46,109	47,120	47,784	47,480	48,583	49,499	50,177
2. Peak Demand	35,271	35,854	36,625	37,174	38,034	38,643	39,436	40,162	40,918	41,657
3. Planned Reserve (1-2)	9,577	10,255	9,180	8,935	9,086	9,141	8,044	8,421	8,581	8,520
4. Planned Reserve (%) (3/2) x 100	27.2	28.6	25.1	24.0	23.9	23.7	20.4	21.0	21.0	20.5
5. Net Transactions	0	0	0	0	0	0	0	0	0	0
6. Total Capability (1+5)	44,848	46,109	45,805	46,109	47,120	47,784	47,480	48,583	49,499	50,177
7. Total Reserve (6-2)	9,577	10,255	9,180	8,935	9,086	9,141	8.044	8,421	8,581	8,520
8. Total Reserve (%) (7/2) x 100	27.2	28.6	25.1	24.0	23.9	23.7	20.4	21.0	21.0	20.5
9. Scheduled Maint. 2/	2,646	2,951	2,703	2,951	2,780	3,058	2,801	3,109	2,920	3,211
10. Capability after Main. (6-9)	42,202	43,158	43,103	43,158	44,340	44,726	44,679	45,474	46,579	46,966
11. Reserve after Maint. (10-2)	6,931	7,304	6,478	5,984	6,306	6,083	5,243	5,312	5,661	5,309
12. Reserv.aft.Maint.(%) (11/2) x 100	19.7	20.4	17.7	16.1	16.6	15.7	13.3	13.2	13.8	12.7
13. Full Forced Outage (F.O.) 2/	2,601	2,490	2,657	2,490	2,733	2,580	2,754	2,624	2,871	2,710
14. Cap.aft. F.O. (10-13)	39,601	40,668	40,446	40,668	41,607	42,146	41,925	42,850	43,708	44,256
15. Avail. Reserve (14-2)	4,330	4,814	3,821	3,494	3,573	3,503	2,489	2,688	2,790	2,599
16. Avail. Reserve (%) (15/2) x 100	12.3	13.4	10.4	9.4	9.4	9.1	6.3	6.7	6.8	6.2
17. Other Unavailable 2/	3,498	3,873	3,573	3,873	3,675	4,014	3,703	4,081	3,861	4,215
18. Actual Capability Avail. (14-17)	36,103	36,795	36,873	36,795	37,932	38,132	38,221	38,769	39,847	40,041
19. Actual Reserve (18-2)	832	941	248	(379)	(102)	(511)	(1,215)	(1,393	(1,071)	(1,616)
20. Actual Reserve (%) (19/2) x 100	2.4	2.6	0.7	(1.0)	(0.3)	(1.3)	(3.1)	(3.5)	(2.6)	(3.9)

1/ Assumes no new unit delays.

2/ Maintenance outages, other unavailable capacity and forced outages were derived from historic data and are actual average values which occurred between 1977 and 1980 at the time of the respective summer and winter seasonal peak demands expressed in constant percent of planned capability.

Based on SERC ERA-411 Report dated April 1, 1981.

Table 7.D.6

Installed Net Generation Capability By Type of Fuel-Mw
VACAR Region

Summer

			Oil			Natural Gas			Hydro			
	Nuclear Steam	Coal Steam	Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage	Other	Planned Capability
1981	8,024	18,630	3,472	1,562	1,046	0	0	0	2,477	1,122	0	36,333
% Total	22.1	51.2	9.6	4.3	2.9	0	0	0	6.8	3.1	0	100.0
1982	10,104	18,743	3,472	1,562	1,046	0	0	0	2,477	1,122	0	38,526
% Total	26.2	48.6	9.1	4.1	2.7	0	0	0	6.4	2.9	0	100.0
1983	10,104	19,506	3,472	1,562	1,046	0	0	0	2,477	1,122	0	39,289
% Total	25.7	49.6	8.8	4.0	2.7	0	0	0	6.3	2.9	0	100.0
1984	12,429	19,956	3,472	1,562	1,046	0	0	0	2,601	1,122	0	42,188
% Total	29.5	47.3	8.2	3.7	2.5	0	0	0	6.2	2.6	0	100.0
1985	12,429	19,956	3,472	1,562	1,046	0	0	0	2,751	1,122	0	42,338
% Total	29.4	47.1	8.2	3.7	2.5	0	0	0	6.5	2.6	0	100.0
1986	14,474	19,956	3,472	1,502	1,046	0	0	0	2,751	1,647	0	44,848
% Total	32.3	44.5	7.7	3.3	2.3	0	0	0	6.2	3.7	0	100.0
1987	14,474	20,406	3,472	1,409	1,046	0	0	0	2,751	2,247	0	45,805
% Total	31.6	44.5	7.6	3.1	2.3	0	0	0	6.0	4.9	0	100.0
1988	15,374	20,906	3,472	1,249	1,046	0	0	0	2,751	2,322	0	47,120
% Total	32.7	44.4	7.4	2.6	2.2	0	0	0	5.8	4.9	0	100.0
1989	15,374	21,356	3,472	1,159	1,046	0	0	0	2,751	2,322	0	47,480
% Total	32.4	45.0	7.3	2.4	2.2	0	0	0	5.8	4.9	0	100.0
1990	16,281	22,076	3,472	1,051	1,046	0	0	0	2,751	2,822	0	49,499
% Total	32.9	44.6	7.0	2.1	2.1	0	0	0	5.6	5.7	0	100.0

This table is based on the SERC April 1, 1981 ERA-411 Report.

Table 7.D.7

Installed Net Generation Capability By Type of Fuel-Mw
VACAR Region

Winter

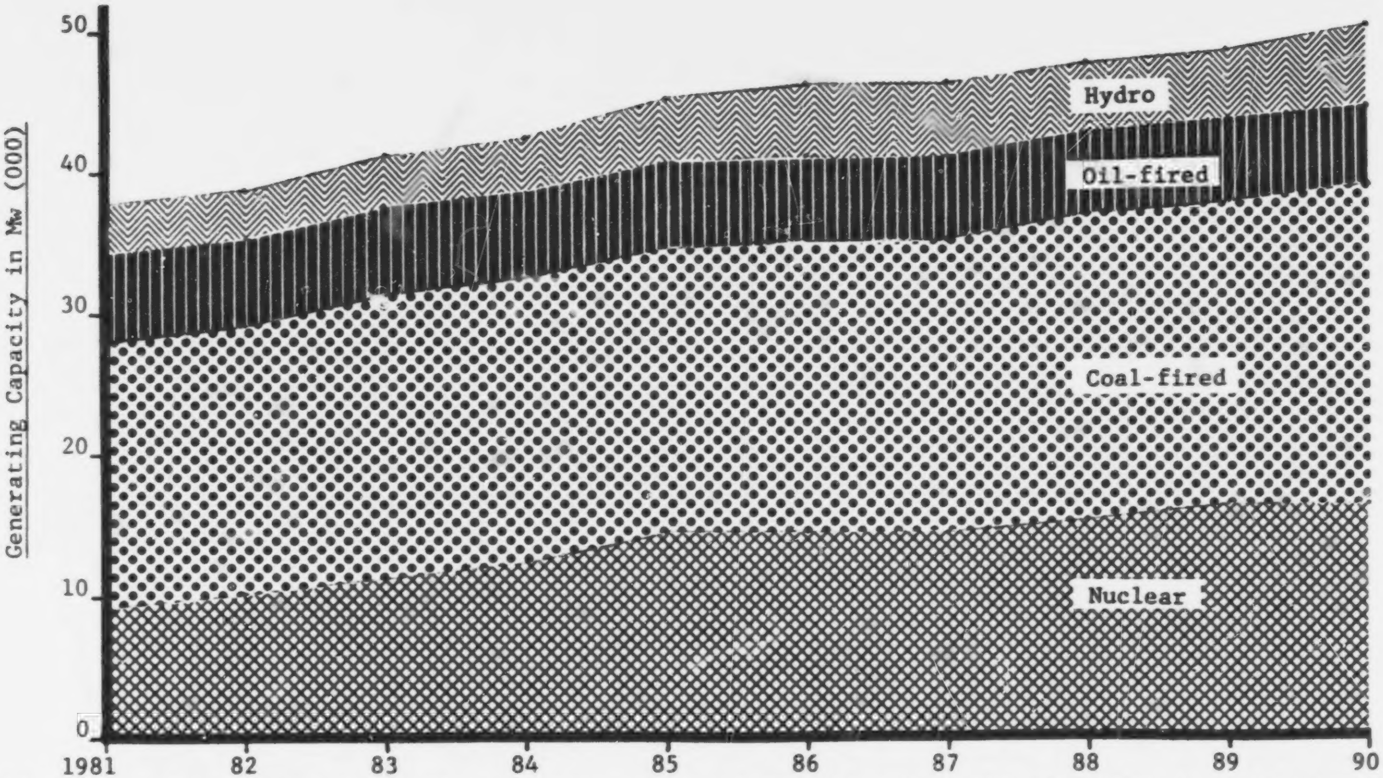
			Oil			Natural Gas			Hydro			
	Nuclear Steam	Coal Steam	Steam	Combust. Turbine	Internal Combust.	Steam	Combust. Turbine	Internal Combust.	Convent.	Pumped Storage	Other	Planned Capability
1981	9,204	18,925	3,527	1,620	1,046	0	0	0	2,467	1,122	0	37,911
% Total	24.3	49.9	9.3	4.3	2.8	0	0	0	6.5	2.9	0	100.0
1982	10,104	18,987	3,527	1,620	1,046	0	0	0	2,467	1,122	0	38,873
% Total	26.0	48.8	9.1	4.2	2.7	0	0	0	6.3	2.9	0	100.0
1983	11,284	20,157	3,527	1,620	1,046	0	0	0	2,591	1,122	0	41,347
% Total	27.3	48.8	8.5	3.9	2.5	0	0	0	6.3	2.7	0	100.0
1984	12,429	20,157	3,527	1,620	1,046	0	0	0	2,741	1,122	0	42,642
% Total	29.1	47.3	8.3	3.8	2.4	0	0	0	6.4	2.7	0	100.0
1985	14,474	20,157	3,527	1,485	1,046	0	0	0	2,741	1,647	0	45,077
% Total	32.1	44.7	7.8	3.3	2.3	0	0	0	6.1	3.7	0	100.0
1986	14,474	20,607	3,527	1,392	1,046	0	0	0	2,741	2,322	0	46,109
% Total	31.4	44.7	7.6	3.0	2.3	0	0	0	5.9	5.1	0	100.0
1987	14,474	20,607	3,527	1,392	1,046	0	0	0	2,741	2,322	0	46,109
% Total	31.4	44.7	7.6	3.0	2.3	0	0	0	5.9	5.1	0	100.0
1988	15,374	21,557	3,527	1,217	1,046	0	0	0	2,741	2,322	0	47,784
% Total	32.2	45.1	7.4	2.5	2.2	0	0	0	5.7	4.9	0	100.0
1989	16,281	21,557	3,527	1,109	1,046	0	0	0	2,741	2,322	0	48,583
% Total	33.5	44.4	7.3	2.3	2.1	0	0	0	5.6	4.8	0	100.0
1990	16,281	22,727	3,527	1,033	1,046	0	0	0	2,741	2,822	0	50,177
% Total	32.4	45.3	7.0	2.1	2.1	0	0	0	5.5	5.6	0	100.0

This table is based on the SERC April 1, 1981 ERA-411 Report.

Figure 7.D.2

VACAR Installed Capacity by Fuel Types[1]

1981-1990



[1] Capacity based on winter rating of units as reported in Item 2 of the SECR April 1, 1981 ERA-411 Report.

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SECTION XIV.8
SOUTHWEST POWER POOL
(SPP)

[redacted]

Southwest Power Pool

Introduction

The Southwest Power Pool (SPP) area includes all of the states of Arkansas, Kansas, Louisiana, and Oklahoma, and part of the states of Mississippi, Missouri, New Mexico, and Texas. The SPP area is divided into three regions: Region 8 (Middle South / Gulf States Group), Region 21 (Missouri - Kansas Group) and Region 22 (Oklahoma Group).

Region 8 (Middle South / Gulf States Group) encompasses most of Arkansas, approximately one-half of Mississippi, all of Louisiana, a small portion of southeast Missouri, and a portions of east central Texas.

Region 21 (Missouri - Kansas Group) covers almost the entire state of Kansas and the remaining part of Missouri that is in the SPP. The majority of the electric systems operating in Region 21 are members of the MOKAN Power Pool.

Region 22 (Oklahoma Group) covers the largest area of the three electric regions in SPP, ranging from western Louisiana to eastern New Mexico. It includes all of Oklahoma and portions of Arkansas, Kansas, Louisiana, Texas, and New Mexico.

Figures 8.1 and 8.2 show graphically how the 10-year summer and winter demand projections of SPP have decreased in the past ten years. These projections, as reported each year in the FPC-383 (1970-1977) and ERA-411 (1978-1981) Reports, held fairly steady around the 9.0 percent per year growth rate from 1970 to 1974. After the oil embargo of late 1973 and early 1974, utility demand forecasts began to drop and by 1981, the 10-year average compound load growth is forecasted to be under 4.0 percent. It should be noted that few, if any, of the FPC-383 or ERA-411 reports have included the identical systems that were included in previous reports. This means that each 10-year load growth forecast was made by a different set of systems. There were, however, a sufficient number of identical systems reporting each year to allow valid comparisons of average compound rates of growth to be made.

The SPP as a group is a predominantly natural gas burning area. The only exception among the individual Electric Regions is the Missouri - Kansas Group (Region 21) which is predominantly coal-fired. In 1980, natural gas produced 58.7 percent of the total generation in the pool. Coal produced 29.1 percent while the use of oil has decreased to 5.9 percent. Nuclear generation has increased slowly to a figure of 4.4 percent.

The SPP has a backbone transmission system at the 500 KV level in Region 8 and at 345 KV in Regions 21 and 22. The 500 KV system was developed primarily to effect a 1500 MW diversity interchange with the Tennessee Valley Authority, which began in June 1967. The interchange was reduced to 1100 MW in 1979 and will be further decreased to 700 MW in 1981 and 200 MW during the 1983-84 winter peak period.

The data used in this report on load and supply for Regions 8, 21, and 22 is based on SPP's April 1, 1981, ERA-411 report. Data from the city of Lafayette, Louisiana, which was received by SPP too late to include in their ERA-411 report, has been included in the PSR staff estimates. Net dependable capability was determined by adding the existing capacity (Item 2-A) and projected capacity (Item 2-B). For the purpose of this report, staff used a May 31 as the in-service cutoff date for including scheduled capacity in the planned capability for the summer peak and November 30 for the winter peak. Using this method the net dependable capability calculated by staff will be different from that reported by SPP in Item 3-A of ERA-411. Table 8.1 shows the difference in capability between SPP's figures shown in Item 3-A of ERA-411 for each Electric Region and the figures calculated using the staff criteria. In some years, due to projected retirements, staff capability estimates were higher than those of SPP.

Table 8.1

Difference In Peak Period Capability Due to Difference In Cut-off Dates 1/ For Including New Generating Units

SPP Regions

Year	Summer (MW) Region 8	Summer (MW) Region 21	Summer (MW) Region 22	Winter (MW) Region 8	Winter (MW) Region 21	Winter (MW) Region 22
1981	124	112	473	-413	-105	10
1982	477	426	563	-390	-147	95
1983	-134	510	213	-636	-170	213
1984	-661	-226	213	-636	-170	11
1985	-202	-324	1261	-664	-222	753
1986	-343	477	753	-688	-317	857
1987	-784	-293	679	-681	-317	679
1988	485	427	679	-660	-263	712
1989	-763	83	1342	-360	-208	724
1980	-305	-228	742	-442	-190	438

1/ Tabulated Difference = (ERA-411 Capacity) - (Capacity Computed by PSR)

Scheduled maintenance, full forced outage, and other unavailable capability are all estimated by PSR with one exception. The 1981 summer peak period scheduled maintenance was used as reported by SPP. All other figures were calculated using a historical percent of net dependable capability as listed in the following table.

Table 8.2

Historical Percentages for Scheduled Maintenance Full Forced Outages, and Other Unavailable Capability

Electric Region	Scheduled Maintenance Summer	Scheduled Maintenance Winter	Full Forced Outage Summer	Full Forced Outage Winter	Other Unavailable Capability Summer	Other Unavailable Capability Winter
Middle South / Gulf States Group (Region 8)	0.7	10.3	8.6	7.6	3.1	3.4
Missouri - Kansas Group (Region 21)	0.9	10.5	6.8	9.8	3.3	5.8
Oklahoma Group (Region 22)	0.1	11.6	2.8	3.3	0.9	0.4

These percentages were calculated using data submitted in FPC Form 12E-2. A historical total for each category was determined for the peak month during the 1977-1980 summers and the 1977-78 through 1979-80 winters. A percent of net dependable capability was calculated for each period for each category to determine the figures shown in Table 8.2.

[redacted]

Delay Costs of Coal-Fired Generating Units

During the last several years, delays in the in-service dates for new large coal-fired generating units have been the rule rather than the exception. Some have been delayed only one or two months and others have been delayed as much as a year. The reasons for these delays are many and varied -- ranging from the lack of money to continue construction, to delays caused by existing and changing government regulations.

The cost of a delay in the in-service date of a coal-fired generating unit affects a utility in three ways: additional construction cost, additional interest during construction, and replacement power cost. Of the three, replacement power cost is usually dominant and is the first to be felt by the consumer. Construction costs and interest during construction related to a delay are usually included in a utility's rate base after the unit is placed in commercial operation. The effect of the additional cost contributes to higher power costs throughout the life of the project.

In order to quantify the magnitude of these delay costs, several systems operating in the SPP were asked to furnish the estimated costs of a 1-month delay in the construction of a coal-fired generating unit. Table 8.3 provides the average costs of a 1-month delay based on the responses received.

Table 8.3

Average Costs of a 1-Month Delay of a Coal-Fired Generating Unit

Average Size (MW)	Added Cost of Construction (Million $'s)	Added Interest (Million $'s)	Replacement Power Costs (Million $'s)	Total Delay Costs (Million $'s)
477	0.3	2.3	4.6	7.2 1/

1/ Total delay costs as reported in the responses ranged from $1.3 million per month to $10.8 million per month.

The costs of construction delays are even more pronounced when the unit delayed is a nuclear unit. The costs of replacement power is then about $500,000 or more per day. The costs of delaying operating licenses for nuclear units are shown in detail in a DOE report to the Nuclear Regulatory Commission dated April 9, 1981.

A. Middle South / Gulf States Group (Electric Region 8)

Table 8A.4 gives the 1977-1980 summer and winter reserves for the Middle South/ Gulf Sates Group (Region 8). As shown on line 20, actual reserves, which includes the effects of net transactions, scheduled maintenance, full forced outages, and other unavailable capability have been adequate for both the summer and winter peak periods.

[redacted]

The actual growth rates of demand and energy are given in Table 8A.1. The sudden drop in demand growth that occurred in 1979 did not occur in 1980 for either the summer or winter peaks.

Table 8A.1

Historical Peak Demand and Energy
Middle South/Gulf States Group
(Region 8)

	Demand				Annual Energy Requirements		Annual Load Factor
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWH)	Growth (%)	(%)
1977	17491	-	12967	-	88644	-	57.9
1978	18091	3.4	13800	6.4	95017	7.2	55.9
1979	18229	0.8	13951	1.1	98145	3.3	61.5
1980	20124	10.4	14760	5.8	102469	4.4	58.2

Table 8A.2 shows the net dependable capability, by fuel type, at the end of 1980. Also listed is the annual generation for each type of fuel. Natural gas continued to generate most of the energy in the Region (72.5 percent in 1980, versus 71.6 percent in 1979). Oil generation decreased from 23.0 percent of total generation to 14.6 percent, while nuclear generation increased from 4.9 percent to 11.5 percent during the same period.

Table 8A.2

1980 Net Dependable Capability and Generation by Fuel Type
Middle South Gulf States Group
(Region 8)

Fuel Type	Net Dependable Capability (MW)	(% of Total)	Generation (GWh)	(% of Total)
Coal	1,055	5.0	845.4	1.2
Oil	4,190	19.7	9,994.1	14.6
Natural Gas	14,228	67.0	49,475.3	72.5
Nuclear	1,694	8.0	7,832.6	11.5
Hydro	69	0.3	99.7	0.2
Other	0	0.0	0.0	0.0
Total	21,236	100.0	68,247.1	100.0

See Appendix C for a detailed analysis of the 1981 summer peak period for Region 8.

Since the Middle South/Gulf States Group is a summer peaking system, the estimated 1981-82 winter peak acutal reserves are more than adequate (28.2 percent). (See Table 8A.5.)

Middle South/Gulf States had three new units projected for 1981 (all coal-fired). These units are Big Cajun No. 2 -- units Nos. 1 and 2 (540 MW each), and White Bluff No. 2 (816 MW).

[redacted]

Region 8 should have adequate capacity and fuel supplies to serve the 1981 peak load requirements.

Future Perspective

The Middle South/Gulf States Group (Region 8) is projecting 8482 MW of additional coal-fired capacity during the 1982-1990 period (see Table 8A.6). In addition, 4166 MW of nuclear capacity will be installed (see Table 8A.7). Coal and nuclear capacity will increase from 5.0 percent and 8.0 percent, respectively, of total capability (see Table 8A.2) in December 1980 to 32.6 percent and 16.8 percent, respectively, by December 1990 (see Table 8A.8). Natural gas and oil-fired capability, although decreasing only slightly in installed megawatts, will decrease substantially in percent of total capability (from 67.0 percent and 19.7 percent in 1980 to 38.5 percent and 11.9 percent, respectively, in 1990).

Total reserves, including imports and exports of power, are projected to range from 22.5 percent of peak demand to 33.9 percent during the summer peak periods from 1982-1990 (see Tables 8A.9 and 8A.10). Actual reserves, which are reserves after scheduled maintenance, full forced outage, and other unavailable capability, will vary from 7.7 percent to 18.5 percent. A possible delay, as assumed by staff, of the coal-fired Nelson Unit No. 6 (540 MW) from the 1982 summer peak to the 1982-83 winter peak would decrease the 1982 summer actual reserve margin to 7.7 percent. Since Region 8 is a summer peaking system, winter reserves are more than adequate. (See Table 8.2 for a list of percentages used to estimate scheduled maintenance, full forced outages, and other unavailable capability.)

The Middle South/Gulf States Group should have adequate generating capacity to supply expected peak demands during the 1982-1990 period. Fuel supplies at the present time appear adequate and reliable; however, the reliability of future fuel supplies cannot be forecasted with any degree of certainty.

The Middle South/Gulf States Group (Region 8) projects three interconnections with adjacent Electric Regions during the 1982-1990 period. These interconnections are 345 KV ties with Region 22 (Oklahoma Group) and two of these are for the purpose of increasing interchange capability. In addition Region 8 is planning to construct 24 transmission lines operating at 500 KV (1005 total miles) during the study period. Table 8A.3 is a list of the number of transmission lines to be built by Region 8 utilities which are not for interconnections to other regions.

Table 8A.3

Projected Construction of Intra-Regional Transmission Lines

Region 8

	1982 - 1990	
Operating Voltage (KV)	Number of Lines	Total Miles
500	24	1005
345	4	156
230	19	269
138	5	83
115	2	22
Totals	54	1535

[redacted]

During the study period (1982-1990) summer and winter peak demands are expected to increase at an average compound rate of 4.3 percent and 4.2 percent per year, respectively (see Table 8A.11). The summer peak demand growth rate is a reduction of 1.4 percent per year from the estimates made in the 1980 ERA-411 Report. Energy requirements are also expected to increase at a 4.2 percent average compound rate per year. The annual load factor will vary slightly from 60.9 percent to 61.4 percent.

Region 8, based upon current estimates, should be able to maintain a reliable system throughout the 1982-1990 period. However, problems could occur if forced outages were to run significantly higher than the 8.6 percent calculated by the staff, shortages of natural gas supplies occur, future coal and nuclear units were delayed considerably, or demand grows at a higher rate than expected.

B. Missouri-Kansas Group (Electric Region 21)

The Missouri-Kansas Group (Region 21) experienced actual reserve of 14.2 percent in the 1980 summer peak period and 50.7 percent in the 1980-81 winter peak period (see Table 8B.4). These reserves and reserves during 1977-1980 were all adequate to assure the reliability of the bulk power system.

Table 8B.1 lists the historical growth rates for demand and energy. Total group figures are much greater in 1980 due to the addition of Associated Electric Cooperative, Inc. (ASEC), which in previous years was included in the MAIN ERA-411 Report. Without ASEC included in the 1980 totals, the growth rates from 1979 to 1980 for summer peak demand, winter peak demand, and annual energy requirements would be 14.9 percent, 6.8 percent, and 5.5 percent, respectively.

Table 8B.1

Historical Peak Demand and Energy
Missouri-Kansas Group
(Region 21)

	Demand				Annual Energy Requirements		Annual Load Factor
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	(%)
1977	7,966	-	5,587	-	34,624	-	49.6
1978	8,454	6.1	5,772	3.3	37,086	7.1	50.1
1979	8,103	-4.2	5,617	-2.7	36,826	-0.7	51.9
1980	10,920	*	7,507	*	46,215	*	48.3

*Associated Electric Cooperative (ASEC) became a member of SPP in 1980. ASEC's summer and winter peak demands were 1,608 MW and 1,506 MW, respectively. Annual 1980 energy was 7,374 GWh.

The Missouri-Kansas Group is heavily dependent upon coal for generation. In 1980, 81.6 percent of its generation came from coal (see Table 8B.2 that follows). Natural gas supplied 17.2 percent of Region 21's generation.

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Table 8B.2

1980 Net Dependable Capability and Generation by Fuel Type
Missouri-Kansas Group
(Region 21)

Fuel Type	Net Dependable Capability (MW)	Net Dependable Capability (% of Total)	Generation (GWh)	Generation (% of Total)
Coal	8,361	67.5	31,331.1	81.6
Oil	1,405	11.3	405.4	1.1
Natural Gas	2,608	21.1	6,603.7	17.2
Nuclear	0	0.0	0.0	0.0
Hydro	16	0.1	52.6	0.1
Other	0	0.0	0.0	0.0
Total	12,390	100.0	38,392.8	100.0

See Appendix C for a detailed analysis of the 1981 summer peak period for Region 21.

Table 8B.5 gives the 1981-82 winter peak supply - demand situation. The Missouri-Kansas Group (Region 21) is a predominantly summer peak system and thus the reserves are more than adequate for the winter period (25.8 percent).

There are only four new units projected for the Region in 1981 -- all hydro. These are the Harry S. Truman Nos. 1 - 4 (26 MW each).

Region 21 should have an adequate supply of capacity as well as adequate fuel supplies to assure the reliability of the area of 1981.

Future Perspective

The Missouri-Kansas Group (MOKAN) is planning 3207 MW of added coal-fired capacity in the 1982-1990 period (see Table 8B.6). Coal, which constituted 67.5 percent of total capability in December 1980, will make up 68.8 percent by December 1990 (see Table 8B.7). Natural gas and oil-fired capacity will both decrease in percent during this period (21.1 percent and 11.3 percent to 15.5 percent and 8.3 percent, respectively). MOKAN's first nuclear unit (Wolf Creek) will be installed in March 1984 which will total 5.5 percent of total capability by 1990. This unit was reported in the 1980 ERA-411 Report to be installed in March 1983. This 1150 MW unit will be jointly owned by Kansas Gas and Electric Co. (425 MW), Kansas City Power & Light Co. (477 MW), Kansas Electric Power Coop. (196 MW), and Kansas Municipal Energy Agency (52 MW).

MOKAN has projected summer total reserves, including net transactions, ranging from a low of 13.7 percent in 1990 to a high of 30.4 percent in 1984 (see Tables 8B.8 and 8B.9). Projected scheduled maintenance, full forced outages, and other unavailable capability will result in actual reserves varying from 1.3 percent in 1990 to 16.4 percent in 1984. Region 21 is a summer peaking area and, thus, winter reserves are more than adequate. (See Table 8.2 for a list of percentages used by PSR to estimate future scheduled maintenance, full forced outages, and other unavailable capability.)

Region 21 is projecting a 345 KV interconnection with Region 20 (MAPP) in 1986 and a 345 KV tie with Region 22 (Oklahoma Group) in 1987 to help relieve overloads. The following Table 8B.3 shows the number and length of transmission line additions planned during the 1982-1990 period.

[redacted]

Table 8B.3

Projected Transmission Line Construction in Region 21 for 1982-1990

Operating Voltage (KV)	Number of Lines	Total Miles
500	1	55
345	28	1278
161	10	142
Totals	39	1475

Summer peak demand is expected to grow at an average compound rate of 3.7 percent per year (see Table 8B.10). This is a reduction from the 4.4 percent given in the 1980 ERA-411 Report. Winter peak demand and energy requirement growth rates are projected to be 4.0 percent and 4.1 percent per year, respectively. Annual load factor is anticipated to be below 50 percent with a range of 48.3 percent to 49.5 percent.

Even though a positive actual reserve margin in 1990 (1.3 percent) is projected for MOKAN, after capacity outages, there could be a reliability problem. Fuel supplies should be adequate and available but forced outages may be higher than projected. PSR used a historical full forced outage rate of 6.8 percent. This was based mainly on small units, whose forced outage rates are generally smaller than those of larger units. With the addition of larger coal-fired units in the future, the forced outage rate could be greater than in previous years. A forced outage rate of 8 percent, for instance, would result in a reserve deficit in 1990. In addition, the demand growth rate would only have to increase slightly over the projected rate to create a reserve shortfall in the latter part of the study period. MOKAN has several 345 KV interconnections with neighboring regions which could help in an emergency.

C. Oklahoma Group (Electric Region 22)

The Oklahoma Group (Region 22) had actual reserve of 13.9 percent during the 1980 summer peak and 39.0 percent during the 1980-81 winter peak (see Table 8C.4). These reserves include the effects of actual scheduled maintenance, full forced outages, and other unavailable capability.

Region 22 experienced a large increase in the growth rate from 1979 to 1980. Summer and winter demands grew at a rate of 14.9 percent and 9.6 percent, respectively, while annual energy requirements grew at a 9.2 percent rate (see Table 8C.1 below).

Table 8C.1

Historical Peak Demand and Energy
Oklahoma Group
(Region 22)

	Demand				Annual Energy Requirements		Annual Load Factor
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWH)	Growth (%)	(%)
1977	12010	-	9403	-	56246	-	53.5
1978	12576	4.7	9156	-2.6	59429	5.7	53.9
1979	12088	-3.9	8981	-2.0	59115	-0.5	55.8
1980	13885	14.9	9841	9.6	64554	9.2	53.1

[redacted]

Table 8C.2 that follows gives the 1980 capability and generation grouped by fuel type. Natural gas continued to account for most of the Region 22 generation (68.0%). This is a reduction from 1979 figure of 72.7 percent. Coal has increased from 18.6 percent of total generation in 1979 to 27.4 percent in 1980.

Table 8C.2

1980 Net Dependable Capability and Generation by Fuel Type
Oklahoma Group
(Region 22)

Fuel Type	Net Dependable Capability		Generation	
	(MW)	(% of Total)	(GWh)	(% of Total)
Coal	5,277	28.2	19,324.4	27.4
Oil	301	1.6	41.6	0.1
Natural Gas	10,776	57.5	47,812.0	68.0
Nuclear	0	0.0	0.0	0.0
Hydro	2,339	12.5	3,088.9	4.4
Other*	42	0.2	78.8	0.1
Total	18,735	100.0	70,345.7	100.0

* Includes a co-generation unit and an expander turbine using hot inert gas from a chemical process.

See Appendix C for a detailed analysis of the 1981 summer peak period for Region 22.

Table 8C.5 shows the 1981-82 winter peak conditions for the Oklahoma Group. The region has more than adequate winter reserve (42.4 percent) since the Oklahoma Group is a summer peaking area.

There is one unit projected for 1981 (GRDA No. 1). This coal-fired unit has a capability of 490 MW.

Region 22 should have an adequate supply of capacity and fuel for the 1981 peak periods.

Future Perspective

The Oklahoma Group (Region 22) is planning to construct only coal-fired capacity during the 1982-1990 study period. A total of 5192 MW of additional coal-fired capacity is projected (see Table 8C.6). In December 1980, coal capacity represented 28.2 percent of total Region 22 capability (see Table 8C.2), while in 1990 this figure is projected to increase to 46.4 percent (see Table 8C.7). Natural gas, which constituted 57.5 percent in 1980, will decrease to 42.5 percent of total capability in 1990.

Projected summer total reserves for Region 22 range from a low of 15.3 percent in 1989 to 27.2 percent in 1982 (see Tables 8C.8 and 8C.9). These figures include the effect of imports and exports of power. Unlike the other regions in the SPP, Oklahoma is a net exporter of power. Actual reserves, which are less than total reserves by scheduled maintenance, full forced outages, and other unavailable capability, will range from 10.7 percent to 22.0 percent. (See Table 8.2 for the list of percentages used by PSR to estimate the three types of unit outages.) If Welsh No. 3 (528 MW) should be delayed from the 1982 summer peak period to the 1982-83 winter peak period, this would decrease the projected 1982 summer actual reserve from 22.0 percent to 18.4 percent.

The Oklahoma Group projects four additional interconnections with adjoining Electric Regions during the 1982-1990 period. There are three 345 KV ties to Region 8 (Middle South/Gulf State Group) planned. Two of these ties are expected to increase interchange capability. Another 345 KV tie is proposed with Region 21 (Missouri-Kansas Group). The following table shows the intra-region transmission lines planned for this period.

Table 8C.3

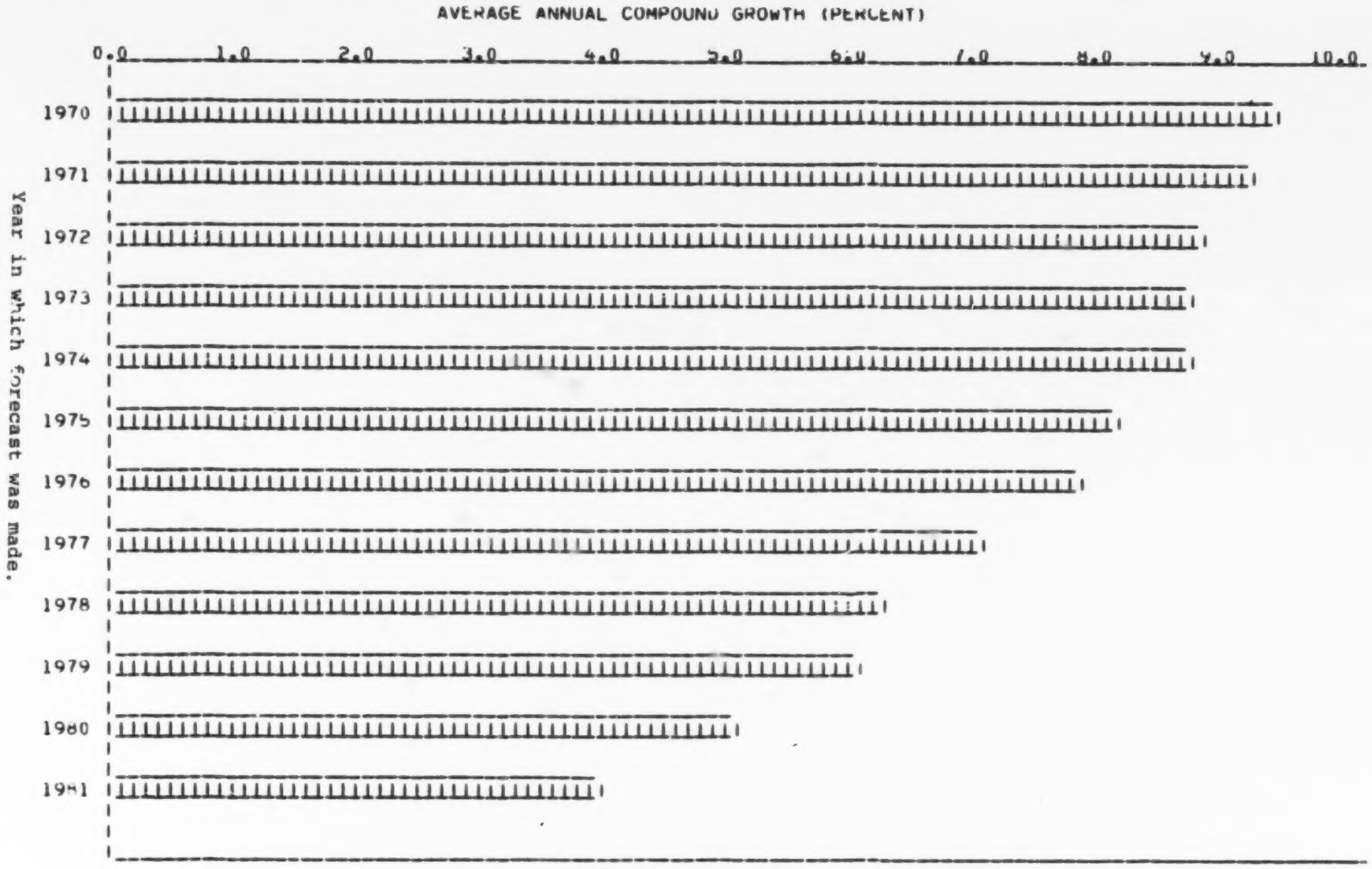
Intra-Regional Transmission Lines Planned by Region 22 for 1982-1990

Operating Voltage	Number of Lines	Total Miles
345	25	1186
230	2	127
161	1	10
Totals	28	1323

Although not listed in the SPP 1981 ERA-411 Report, the Central and South West Corporation plans to construct two ± 500 KV direct current transmission line interconnections with the Electric Reliability Council of Texas (Region 23). These ties will originate from facilities owned by systems operating in Region 22. The interconnecting D.C. ties are proposed for service in the mid-1980's; however, the lines cannot be constructed until the plan is approved by the Federal Energy Regulatory Commission.

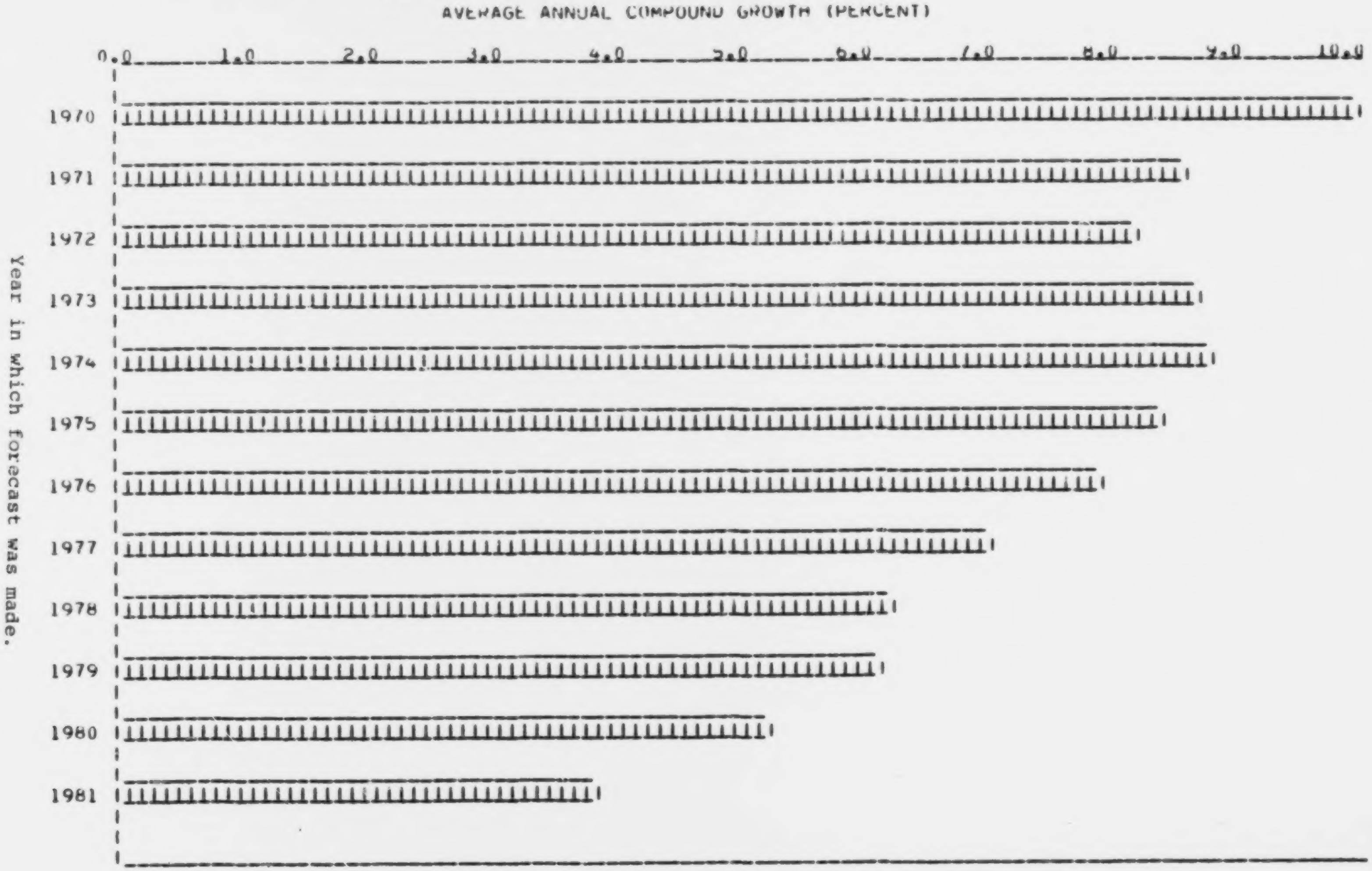
The summer peak demand growth rate is forecasted to increase at an average rate of 3.7 percent per year (see Table 8C.10). This is a 2.0 percent per year reduction in growth from last year's ERA-411 Report. Winter peak demand and energy requirements are expected to increase at a rate of 3.8 percent and 4.3 percent, respectively. The annual load factor has been projected to range from 53.0 percent to 55.5 percent.

The Oklahoma Group should have adequate capacity to supply projected loads throughout the 1982-1990 period. Fuel supplies appear adequate at present but with natural gas continuing to constitute a substantial part of the Oklahoma generation any major disruption of gas supplies would be a threat to area reliability. In addition, Region 22 has had a very low historical average full forced outage rate during its summer peak (2.8 percent), and this could be increased greatly in the future due to the number of new large coal-fired units projeted during this decade. Coal units have generally shown larger forced outage rates than gas-fired units. Large units usually have experienced greater forced outage rates than small units, and new units usually experience larger forced outage rates during the first few years of operation.



TEN YEAR ESTIMATES OF SUMMER PEAK DEMAND AS REPORTED BY THE SOUTHWEST POWER POOL
IN ITS FPC-383 AND ERA-411 ANNUAL REPORTS

Figure 8.1



TEN YEAR ESTIMATES OF WINTER PEAK DEMAND AS REPORTED BY THE SOUTHWEST POWER POOL IN ITS FPC-383 AND ERA-411 ANNUAL REPORTS

Figure 8.2

Table 8A.4

Historical Capability (MW) and Reserves (MW and Percent)
Middle South-Gulf States Group (Region 8)

	Summer				Winter			
	1977	1978	1979	1980	1977/78	1978/79	1979/80	1980/81
1. Planned Capability	20,151	20,142	20,143	21,469	20,136	20,161	20,637	22,315
2. Peak Demand	17,491	18,091	18,229	20,124	12,967	13,800	13,951	14,760
3. Planned Reserves (1-2)	2,660	2,051	1,914	1,345	7,169	6,361	6,686	7,556
4. Planned Reserves (%) (3/2) x 100	15.2	11.3	10.5	6.7	55.3	46.1	47.9	51.2
5. Net Transactions (Imports-Exports)	1,949	3,779	3,138	3,905	1,219	787	2,303	2,753
6. Total Capability (1+5)	22,100	23,921	23,281	25,374	21,355	20,948	22,940	25,069
7. Total Reserves (6-2)	4,609	5,830	5,052	5,250	8,388	7,148	8,989	10,309
8. Total Reserves (%) (7/2) x 100	26.4	32.2	27.7	26.1	64.7	51.8	64.4	69.8
9. Scheduled Maintenance	260	265	0	0	2,209	1,774	2,292	3,887
10. Capability after Maintenace (6-9)	21,840	23,656	23,281	25,374	19,146	19,174	20,648	21,182
11. Reserves after Maintenance (10-2)	4,349	5,565	5,052	5,250	6,179	5,374	6,697	6,422
12. Reserves after Maintenace (11/2) x 100	24.9	30.8	27.7	26.1	47.7	38.9	48.0	43.5
13. Full Forced Outages	380	1,940	2,336	2,456	2,430	2,017	1,410	2,997
14. Capability after Full Forced Outages (10x13)	21,460	21,716	20,945	22,918	16,716	17,157	19,238	18,185
15. Reserves after Full Forced Outages (14x2)	3,969	3,625	2,716	2,794	3,749	3,357	5,287	3,425
16. Reserves (%) after Full Forced Outages (15/2) x 100	22.7	20.0	14.9	13.9	28.9	24.3	37.9	23.2
17. Other Unavailable Capability	665	1,222	453	177	808	762	489	448
18. Actual Capability (14-17)	20,795	20,494	20,492	22,741	15,908	16,395	18,749	17,737
19. Actual Reserves (18-2)	3,304	2,403	2,263	2,617	2,941	2,595	4,798	2,977
20. Actual Reserves (%) (19/2) x 100	18.9	13.3	12.4	13.0	22.7	18.8	34.4	20.2

Source: FPC Form 12E-2 and ERA-119M

Table 8A.5

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
MIDDLE SOUTH - GULF STATES GROUP (REGION 8)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	22460	23149
2. PEAK DEMAND	19892	15085
3. PLANNED RESERVES (1-2)	2568	8064
4. PLANNED RESERVES (%) (3/2)X100	12.9	53.5
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	1852	1121
6. TOTAL CAPABILITY (1+5)	24312	24270
7. TOTAL RESERVES (6-2)	4420	9185
8. TOTAL RESERVES (%) (7/2)X100	22.2	60.9
9. SCHEDULED MAINTENANCE 1/	0	2384
10. CAPABILITY AFTER MAINTENANCE (6-9)	24312	21886
11. RESERVES AFTER MAINTENANCE (10-2)	4420	6801
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	22.2	45.1
13. FULL FORCED OUTAGES 1/	1932	1759
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	22380	20127
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2488	5042
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	12.5	33.4
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	696	787
18. ACTUAL CAPABILITY (14-17)	21684	19340
19. ACTUAL RESERVES (18-2)	1792	4255
20. ACTUAL RESERVES (%) (19/2)X100	9.0	28.2

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

[redacted]

Table 8A.6

Projected Coal-fired Generating Units for the Period 1981-1990 as PRojected in the April 1, 1981, ERA-411 Report of SPP

Middle South Gulf States Group
(Region 8)

Unit Name	Capability (MW)	As Reported April 1 1981	As Reported April 1 1980	Company
Big Cajun No. 2 Unit 1	540	3-81	5-80	Cajun Electric Power Coop.
Big Cajun No. 2, Unit 2	540	4-81	1-81	Cajun Electric Power Coop.
White Bluff No. 2	816[1]	8-81	5-81	Arkansas Power & Light Co.
Rodemacher No. 2	530[2]	1-82	1-82	Central Louisiana Electric Co.
Nelson No. 6	540[3]	5-82	3-82	Gulf States Utilities Co.
Independence No. 1	816[4]	1-83	1-83	Arkansas Power & Light Co.
Big Cajun No. 2, Unit 3	540[5]	6-83	1-83	Cajun Electric Power Coop.
Independence No. 2	816[4]	1-85	1-85	Arkansas Power & Light Co.
Big Cajun No. 3, Unit 1	540[6]	6-85	1-85	Cajun Electric Power Coop.
Dolet Hills No. 1	640[7]	3-86	3-86	Central Louisiana Electric Co.
Big Cajun No. 4, Unit 1	540[8]	6-86	1-86	Cajun Electric Power Coop.
Nelson No. 5	540	4-87	4-85	Gulf States Utilities Co.
Big Cajun No. 3, Unit 2	540[8]	6-88	1-88	Cajun Electric Power Coop.
Wilton No. 1	800	6-88	1-87	Middle South Utilities Co.
East Orleans No. 1	800	1-89	1-88	Middle South Utilities Co.
Lovelady No. 1	300	1-90	10-86	Gulf States Utilities Co.
Alec No. 1	800[9]	1-90	1-89	Arkansas Power & Light Co.
Big Cajun No. 4, Unit 2	540	6-90	--	Cajun Electric Power Coop.
Total	11,178*			

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[1] Joint ownership: Arkansas Power & Light Co. (57-percent), Arkansas Electric Coop. (35 percent), City of Jonesboro (5 percent), and Conway Corporation and West Memphis Utility Dept. (3 percent).

[2] Joint ownership: Central Louisiana Electric Co. (50-percent) and City of Lafayette (50-percent).

[3] Joint ownership: Gulf States Utilities Co. (70-percent), Sam Rayburn G&T Coop. (10-percent) and Sam Rayburn Municipal Power System (20-percent).

[4] Joint ownership: Arkansas Power & Light Co. (56.5-percent), Arkansas Electric Coop. (35-percent), City of Jonesboro (5-percent), Conway Corporation (2-percent), West Memphis Utility Dept. (1-percent), and Osceola Municipal Light & Power Plant (0.5 percent).

[5] Joint ownership: Cajun Electric Power Coop. (51-percent), Gulf States Utilities Co. (42-percent), and Sam Rayburn G&T Coop. (7-percent).

[6] Joint ownership: Cajun Electric Power Coop. (68-percent), Gulf States Utilities Co. (25-percent), and Sam Rayburn G&T Coop. (7-percent).

[7] Joint ownership: Central Louisiana Electric Co. (50-percent) and Southwestern Electric Power Co. (50-percent) (Region 22).

[8] Joint ownership: Cajun Electric Power Coop. (58-percent), Gulf States Utilities Co. (25-percent), Sam Rayburn G&T Coop. (7-percent) and Louisiana Electric Power Agency (10-percent).

[9] Joint ownership: Arkansas Power & Light Co. (60-percent), Arkansas Electric Coop. (35-percent), and City of Jonesboro (5-percent).

*Of this amount, 320 MW is allocated to Region 22 and 480 MW is allocated to systems within Region 8 that do not report their data in the SPP ERA-411 report.

[redacted]

Table 8A.7

Projected Nuclear Generating Units for the Period 1981-1990 as Projected in the April 1, 1981, ERA-411 Report of SPP

Middle South Gulf States Group (Region 8)

Unit Name	Capability (MW)	As Reported April 1 1981	1980	Company
Grand Gulf No. 1	1,250[1]	6-82	4-82	Middle South Energy, Inc.
Waterford No. 3	1,104	3-83	2-82	Louisiana Power & Light Co.
River Bend No. 1	940[2]	4-84	4-84	Gulf States Utilities Co.
Grand Gulf No. 2	1,250[1]	4-88	4-85	Middle South Energy, Inc.

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[1] Joint ownership: Middle South Energy, Inc. (87.52 percent), South Mississippi Electric Power Assn. (10-percent) and Municipal Energy Agency of Mississippi (2.48-percent).

[2] Joint ownership: Gulf States Utilities Co. (63-percent), Cajun Electric Power Coop. (30-percent), and Sam Rayburn G&T Coop. (7-percent).

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Table 8A.8

Summer and Winter Capability by Fuel Type
(Megawatts)
1981-1990

Middle South - Gulf States Group
(Region 8)

	1981		1982		1983		1984		1985	
Fuel Type	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Coal	2,176	2,968	3,800	3,800	4,587	5,089	5,089	5,089	5,876	6,378
Oil	4,190	4,190	4,170	4,170	4,210	4,210	4,210	4,210	4,210	4,210
Gas	14,331	14,228	14,278	14,175	14,339	14,240	14,240	14,137	14,151	14,048
Nuclear	1,694	1,694	1,694	2,788	3,892	3,892	4,766	4,766	4,766	4,766
Hydro	69	69	69	69	69	69	69	69	69	69
Other	0	0	0	0	0	0	0	0	0	0
TOTAL	22,460	23,149	24,011	25,002	27,097	27,496	28,374	28,271	29,072	29,471

	1986		1987		1988		1989		1990	
Fuel Type	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Coal	6,698	7,146	7,686	7,686	7,686	8,934	9,734	9,734	10,834	11,374
Oil	4,210	4,210	4,160	4,160	4,160	4,160	4,160	4,160	4,160	4,160
Gas	13,990	13,887	13,990	13,887	13,854	13,751	13,560	13,457	13,560	13,457
Nuclear	4,766	4,766	4,766	4,766	5,860	5,860	5,860	5,860	5,860	5,860
Hydro	69	69	69	69	69	69	69	69	69	69
Other	0	0	0	0	0	0	0	0	0	0
TOTAL	29,733	30,078	30,671	30,568	31,629	32,774	33,383	33,280	34,483	34,920

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Table 8A.9

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
MIDDLE SOUTH - GULF STATES GROUP (REGION 8)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	24011	25002	27097	27496	28374	28271	29072	29471
2. PEAK DEMAND	20935	15799	21779	16436	22819	17151	23742	17845
3. PLANNED RESERVES (1-2)	3076	9203	5318	11060	5555	11120	5330	11626
4. PLANNED RESERVES (%) (3/2)X100	14.7	58.3	24.4	67.3	24.3	64.8	22.4	65.1
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	2053	1383	2072	1490	1466	1272	1320	1126
6. TOTAL CAPABILITY (1+5)	26064	26385	29169	28986	29840	29543	30392	30597
7. TOTAL RESERVES (6-2)	5129	10586	7390	12550	7021	12392	6650	12752
8. TOTAL RESERVES (%) (7/2)X100	24.5	67.0	33.9	76.4	30.8	72.3	28.0	71.5
9. SCHEDULED MAINTENANCE 1/	168	2575	190	2832	199	2912	204	3036
10. CAPABILITY AFTER MAINTENANCE (6-9)	25896	23810	28979	26154	29641	26631	30188	27561
11. RESERVES AFTER MAINTENANCE (10-2)	4961	8011	7200	9718	6822	9480	6446	9716
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	23.7	50.7	33.1	59.1	29.9	55.3	27.2	54.4
13. FULL FORCED OUTAGES 1/	2065	1900	2330	2090	2440	2149	2500	2240
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	23831	21910	26649	24064	27201	24482	27688	25321
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2896	6111	4870	7628	4382	7331	3946	7476
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	13.8	38.7	22.4	46.4	19.2	42.7	16.6	41.9
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	744	850	840	935	880	961	901	1002
18. ACTUAL CAPABILITY (14-17)	23087	21060	25809	23129	26321	23521	26787	24319
19. ACTUAL RESERVES (18-2)	2152	5261	4030	6693	3502	6370	3045	6474
20. ACTUAL RESERVES (%) (19/2)X100	10.3	33.3	18.5	40.7	15.3	37.1	12.8	36.3

COAL UNIT DELAYS ASSUMED POSSIBLE BY ERA

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. POSSIBLE COAL DELAYS	540	0	0	0	0	0	0	0
22. ACTUAL CAPABILITY WITH COAL DELAYS (18-21)	22547	21060	25809	23129	26321	23521	26787	24319
23. ACTUAL RESERVES WITH COAL DELAYS (22-2)	1612	5261	4030	6693	3502	6370	3045	6474
24. ACTUAL RESERVES (%) WITH COAL DELAYS (23/2)X100	7.7	33.3	18.5	40.7	15.3	37.1	12.8	36.3

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

. Table 8A.10

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990

MIDDLE SOUTH - GULF STATES GROUP (REGION 8)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	29733	30078	30671	30568	31629	32774	33383	33280	34483	34920
2. PEAK DEMAND	24781	18625	25665	19293	26724	20088	27794	20891	29016	21812
3. PLANNED RESERVES (1-2)	4952	11453	5006	11275	4905	12686	5589	12389	5467	13108
4. PLANNED RESERVES (%) (3/2)X100	20.0	61.5	19.5	58.4	18.4	63.2	20.1	59.3	18.8	60.1
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	1204	1010	1211	1017	1200	1007	1058	864	1052	858
6. TOTAL CAPABILITY (1+5)	30937	31088	31882	31585	32829	33781	34441	34144	35535	35778
7. TOTAL RESERVES (6-2)	6156	12463	6217	12292	6105	13693	6647	13253	6519	13966
8. TOTAL RESERVES (%) (7/2)X100	24.8	66.9	24.2	63.7	22.8	68.2	23.9	63.4	22.5	64.0
9. SCHEDULED MAINTENANCE 1/	208	3098	215	3149	221	3376	234	3428	241	3597
10. CAPABILITY AFTER MAINTENANCE (6-9)	30729	27990	31667	28436	32608	30405	34207	30716	35294	32181
11. RESERVES AFTER MAINTENANCE (10-2)	5948	9365	6002	9143	5884	10317	6413	9825	6278	10369
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	24.0	50.3	23.4	47.4	22.0	51.4	23.1	47.0	21.6	47.5
13. FULL FORCED OUTAGES 1/	2557	2286	2638	2323	2720	2491	2871	2529	2966	2654
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	28172	25704	29029	26113	29888	27914	31336	28187	32328	29527
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	3391	7079	3364	6820	3164	7826	3542	7296	3312	7715
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	13.7	38.0	13.1	35.3	11.8	39.0	12.7	34.9	11.4	35.4
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	922	1023	951	1039	980	1114	1035	1132	1069	1187
18. ACTUAL CAPABILITY (14-17)	27250	24681	28078	25074	28908	26800	30301	27055	31259	28340
19. ACTUAL RESERVES (18-2)	2469	6056	2413	5781	2184	6712	2507	6164	2243	6528
20. ACTUAL RESERVES (%) (19/2)X100	10.0	32.5	9.4	30.0	8.2	33.4	9.0	29.5	7.7	29.9

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM 12E-2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

Table 8A.11

PROJECTED ENERGY AND DEMAND GROWTH RATES

Middle South - Gulf States Group
(Region 8)

Year	Energy Requirements		Summer Peak Demand		Winter Peak Growth		Annual Load Factor
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	(%)
1982	112,307	4.6	20,935	5.2	15,799	4.7	61.2
1983	116,215	3.5	21,779	4.0	16,436	4.0	60.9
1984	121,928	4.9	22,819	4.8	17,151	4.4	61.0
1985	126,850	4.0	23,742	4.0	17,845	4.0	61.0
% Growth 1982-85		4.3		4.5		4.3	
1986	132,448	4.4	24,781	4.4	18,625	4.4	61.0
1987	138,027	4.2	25,665	3.6	19,293	3.6	61.4
1988	143,614	4.0	26,724	4.1	20,008	4.1	61.3
1989	149,075	3.8	27,794	4.0	20,891	4.0	61.2
1990	155,505	4.3	29,016	4.4	21,812	4.4	61.2
% Growth 1986-90		4.1		4.1		4.1	
% Growth 1982-90		4.2		4.3		4.2	

Table 8B.4

Historical Capability (MW) and Reserves (MW and Percent)
Missouri-Kansas Group (Region 21)

	Summer				Winter			
	1977	1978	1979	1980	1977/78	1978/79	1979/80	1980/81
1. Planned Capability	9,888	10,173	10,392	13,291	9,846	10,333	10,451	13,357
2. Peak Demand	7,966	8,454	8,103	10,920	5,587	5,772	5,617	7,507
3. Planned Reserves (1-2)	1,922	1,719	2,289	2,371	4,259	4,561	4,834	5,850
4. Planned Reserves (%) (3/2) x 100	24.1	20.3	28.2	21.7	76.2	79.0	86.1	77.9
5. Net Transactions (Imports-Exports)	213	922	751	897	17	576	984	-340
6. Total Capability (1+5)	10,101	11,095	11,143	14,188	9,863	10,909	11,435	13,017
7. Total Reserves (6-2)	2,135	2,641	3,040	3,268	4,276	5,137	5,818	5,510
8. Total Reserves (%) (7/2) x 100	26.8	31.2	37.5	29.9	76.5	89.0	103.6	73.4
9. Scheduled Maintenance	34	122	177	67	738	775	1,711	512
10. Capability after Maintenace (6-9)	10,067	10,973	10,966	14,121	9,125	10,134	9,724	12,505
11. Reserves after Maintenance (10-2)	2,101	2,519	2,863	3,201	3,538	4,362	4,107	4,998
12. Reserves after Maintenace (11/2) x 100	26.4	29.8	35.3	29.3	63.3	75.6	73.1	66.6
13. Full Forced Outages	360	351	945	1,458	255	1,615	1,156	715
14. Capability after Full Forced Outages (10x13)	9,707	10,622	10,021	12,663	8,870	8,519	8,568	11,790
15. Reserves after Full Forced Outages (14x2)	1,741	2,168	1,918	1,743	3,283	2,747	2,951	4,283
16. Reserves (%) after Full Forced Outages (15/2) x 100	21.9	25.6	23.7	16.0	58.8	47.6	52.5	57.1
17. Other Unavailable Capability	350	403	431	196	1,040	355	340	477
18. Actual Capability (14-17)	9,357	10,219	9,590	12,467	7,830	8,164	8,228	11,313
19. Actual Reserves (18-2)	1,391	1,765	1,487	1,547	2,243	2,392	2,611	3,806
20. Actual Reserves (%) (19/2) x 100	17.5	20.9	18.4	14.2	40.1	41.4	46.5	50.7

Source: FPC Form 12E-2 and ERA-119M

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Table 8B.5

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
MISSOURI-KANSAS GROUP (REGION 21)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	12310	12673
2. PEAK DEMAND	10461	7685
3. PLANNED RESERVES (1-2)	1849	4988
4. PLANNED RESERVES (%) (3/2)X100	17.7	64.9
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	367	302
6. TOTAL CAPABILITY (1+5)	12677	12975
7. TOTAL RESERVES (6-2)	2216	5290
8. TOTAL RESERVES (%) (7/2)X100	21.2	68.8
9. SCHEDULED MAINTENANCE 1/	0	1331
10. CAPABILITY AFTER MAINTENANCE (6-9)	12677	11644
11. RESERVES AFTER MAINTENANCE (10-2)	2216	3959
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	21.2	51.5
13. FULL FORCED OUTAGES 1/	837	1242
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	11840	10402
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1379	2717
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	13.2	35.4
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	406	735
18. ACTUAL CAPABILITY (14-17)	11434	9667
19. ACTUAL RESERVES (18-2)	973	1982
20. ACTUAL RESERVES (%) (19/2)X100	9.3	25.8

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

[redacted]

Table 8B.6

Projected Coal-fired Generating Units for the Period 1981-1990 as Projected in the April 1, 1981, ERA-411 Report of SPP

Missouri - Kansas Group
(Region 21)

Unit Name	Capability (MW)	As Reported April 1 1981	As Reported April 1 1980	Company
Thomas Hill No. 3	630	6-82	6-82	Associated Electric Coop.
Holcomb No. 1	280	5-83	6-83	Sunflower Electric Coop.
Jeffrey No. 3	680 1/	6-83	6-83	Kansas Power & Light Co.
Jeffrey No. 4	680 1/	6-86	6-85	Kansas Power & Light Co.
Undetermined	630	6-88	--	Associated Electric Coop.
Unknown	90	6-89	6-88	Empire District Electric Co.
Base Load Capacity	117	6-89	--	St. Joseph Power & Light Co.
Unknown	100	5-90	5-88	Missouri Public Service Co.
Total	1,307			

1/ Joint ownership: Kansas Power & Light Co. (64-percent), Kansas Gas & Electric Co. (20-percent), Missouri Public Service Co. (8-percent), and Central Telephone & Utilities Corp., Western Power Division (8-percent).

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Table 8B.7

Summer and Winter Capability by Fuel Type
(Megawatts)
1981-1990

Missouri - Kansas Group
(Region 21)

Fuel Type	1981 Summer	1981 Winter	1982 Summer	1982 Winter	1983 Summer	1983 Winter	1984 Summer	1984 Winter	1985 Summer	1985 Winter
Coal	8,454	8,361	8,496	9,015	9,326	9,975	9,979	9,948	9,979	9,825
Oil	1,199	1,505	1,289	1,505	1,289	1,505	1,289	1,425	1,229	1,425
Gas	2,641	2,687	2,641	2,687	2,641	2,605	2,559	2,605	2,559	2,550
Nuclear	0	0	0	0	0	0	902	902	902	902
Hydro	16	120	120	120	120	178	178	178	178	230
Other	0	0	0	0	0	0	0	0	0	0
TOTAL	12,310	12,673	12,546	13,327	13,376	14,263	14,907	15,058	14,847	14,932

Fuel Type	1986 Summer	1986 Winter	1987 Summer	1987 Winter	1988 Summer	1988 Winter	1989 Summer	1989 Winter	1990 Summer	1990 Winter
Coal	9,856	10,505	10,536	10,505	10,536	11,135	11,166	11,338	11,473	11,381
Oil	1,209	1,405	1,209	1,405	1,180	1,376	1,180	1,376	1,180	1,376
Gas	2,504	2,640	2,594	2,640	2,594	2,640	2,543	2,570	2,524	2,570
Nuclear	902	902	902	902	902	902	902	902	902	902
Hydro	230	230	230	230	230	230	230	230	230	230
Other	0	0	0	0	0	0	0	83	83	83
TOTAL	14,701	15,682	15,471	15,682	15,442	16,283	16,021	16,499	16,392	16,542

Table 8B.8

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
MISSOURI-KANSAS GROUP (REGION 21)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	12546	13327	13376	14263	14907	15058	14847	14932
2. PEAK DEMAND	10776	7885	11198	8219	11653	8579	12144	8961
3. PLANNED RESERVES (1-2)	1770	5442	2178	6044	3254	6479	2703	5971
4. PLANNED RESERVES (%) (3/2)X100	16.4	69.0	19.4	73.5	27.9	75.5	22.3	66.6
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	300	238	333	313	292	324	277	312
6. TOTAL CAPABILITY (1+5)	12846	13565	13709	14576	15199	15382	15124	15244
7. TOTAL RESERVES (6-2)	2070	5680	2511	6357	3546	6803	2980	6283
8. TOTAL RESERVES (%) (7/2)X100	19.2	72.0	22.4	77.3	30.4	79.3	24.5	70.1
9. SCHEDULED MAINTENANCE 1/	113	1399	120	1498	134	1581	134	1568
10. CAPABILITY AFTER MAINTENANCE (6-9)	12733	12166	13589	13078	15065	13801	14990	13676
11. RESERVES AFTER MAINTENANCE (10-2)	1957	4281	2391	4859	3412	5222	2846	4715
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	18.2	54.3	21.4	59.1	29.3	60.9	23.4	52.6
13. FULL FORCED OUTAGES 1/	853	1306	910	1398	1014	1476	1010	1463
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	11880	10860	12679	11680	14051	12325	13980	12213
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1104	2975	1481	3461	2398	3746	1836	3252
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	10.2	37.7	13.2	42.1	20.6	43.7	15.1	36.3
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	414	773	441	827	492	873	490	866
18. ACTUAL CAPABILITY (14-17)	11466	10087	12238	10853	13559	11452	13490	11347
19. ACTUAL RESERVES (18-2)	690	2202	1040	2634	1906	2873	1346	2386
20. ACTUAL RESERVES (%) (19/2)X100	6.4	27.9	9.3	32.0	16.4	33.5	11.1	26.6

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

Table 8B.9

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990
MISSOURI-KANSAS GROUP (REGION 21)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	14701	15682	15471	15682	15442	16283	16021	16499	16392	16542
2. PEAK DEMAND	12597	9323	13062	9716	13550	10130	14045	10549	14553	10978
3. PLANNED RESERVES (1-2)	2104	6359	2409	5966	1892	6153	1976	5950	1839	5564
4. PLANNED RESERVES (%) (3/2)X100	16.7	68.2	18.4	61.4	14.0	60.7	14.1	56.4	12.6	50.7
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	164	202	140	181	97	141	168	215	154	204
6. TOTAL CAPABILITY (1+5)	14865	15884	15611	15863	15539	16424	16189	16714	16546	16746
7. TOTAL RESERVES (6-2)	2268	6561	2549	6147	1989	6294	2144	6165	1993	5768
8. TOTAL RESERVES (%) (7/2)X100	18.0	70.4	19.5	63.3	14.7	62.1	15.3	58.4	13.7	52.5
9. SCHEDULED MAINTENANCE 1/	132	1647	139	1647	139	1710	144	1732	148	1737
10. CAPABILITY AFTER MAINTENANCE (6-9)	14733	14237	15472	14216	15400	14714	16045	14982	16398	15009
11. RESERVES AFTER MAINTENANCE (10-2)	2136	4914	2410	4500	1850	4584	2000	4433	1845	4031
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	17.0	52.7	18.5	46.3	13.7	45.3	14.2	42.0	12.7	36.7
13. FULL FORCED OUTAGES 1/	1000	1537	1052	1537	1050	1596	1089	1617	1115	1621
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	13733	12700	14420	12679	14350	13118	14956	13365	15283	13388
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1136	3377	1358	2963	800	2988	911	2816	730	2410
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	9.0	36.2	10.4	30.5	5.9	29.5	6.5	26.7	5.0	22.0
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	485	910	511	910	510	944	529	957	541	959
18. ACTUAL CAPABILITY (14-17)	13248	11790	13909	11769	13840	12174	14427	12408	14742	12429
19. ACTUAL RESERVES (18-2)	651	2467	847	2053	290	2044	382	1859	189	1451
20. ACTUAL RESERVES (%) (19/2)X100	5.2	26.5	6.5	21.1	2.1	20.2	2.7	17.6	1.3	13.2

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM 12E-2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

Table 8B.10

PROJECTED ENERGY AND DEMAND GROWTH RATES

Missouri - Kansas Group
(Region 21)

Year	Energy Requirements		Summer Peak Demand		Winter Peak Growth		Annual Load Factor
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	(%)
1982	45,628	3.5	10,776	3.0	7,885	2.6	48.3
1983	47,597	4.3	11,198	3.9	8,219	4.2	48.5
1984	49,227	3.4	11,653	4.1	8,579	4.4	46.3
1985	51,420	4.5	12,144	4.2	8,961	4.5	48.3
% Growth 1982-85		3.9		3.8		3.9	
1986	53,695	4.4	12,597	3.7	9,323	4.0	48.7
1987	55,894	4.1	13,062	3.7	9,716	4.2	48.8
1988	58,659	4.9	13,550	3.7	10,130	4.3	49.4
1989	60,323	2.8	14,045	3.7	10,549	4.1	49.0
1990	63,081	4.6	14,553	3.6	10,978	4.1	49.5
% Growth 1986-90		4.2		3.7		4.1	
% Growth 1982-90		4.1		3.7		4.0	

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Table 8C.4

Historical Capability (MW) and Reserves (MW and Percent)
Oklahoma Group (Region 22)

	Summer				Winter			
	1977	1978	1979	1980	1977/78	1978/79	1979/80	1980/81
1. Planned Capability	14,650	16,140	16,526	18,374	15,468	16,609	17,473	19,113
2. Peak Demand	12,010	12,576	12,088	13,885	9,403	9,15[illegible]	8,981	9,841
3. Planned Reserves (1-2)	2,640	3,564	4,438	4,489	6,065	7,453	8,492	9,272
4. Planned Reserves (%) (3/2) x 100	22.0	28.3	36.7	32.3	64.5	81.4	94.6	84.2
5. Net Transactions (Imports-Exports)	-260	-1,070	-537	-1,966	-1,730	-1,651	-2,349	-1,599
6. Total Capability (1+5)	14,390	15,070	15,989	16,408	13,738	14,958	15,124	17,514
7. Total Reserves (6-2)	2,380	2,494	3,901	2,523	4,335	5,802	6,143	7,673
8. Total Reserves (%) (7/2) x 100	19.8	19.8	32.3	18.2	46.1	63.4	68.4	78.0
9. Scheduled Maintenance	18	18	35	0	1,874	2,086	1,776	2,797
10. Capability after Maintenace (6-9)	14,372	15,052	15,954	16,408	11,864	12,872	13,348	14,717
11. Reserves after Maintenance (10-2)	2,362	2,476	3,866	2,523	2,461	3,716	4,367	4,876
12. Reserves after Maintenace (11/2) x 100	19.7	19.7	32.0	18.2	26.2	40.6	48.6	49.5
13. Full Forced Outages	94	170	1,159	483	440	632	584	1,024
14. Capability after Full Forced Outages (10x13)	14,278	14,882	14,795	15,925	11,424	12,240	12,764	13,693
15. Reserves after Full Forced Outages (14x2)	2,268	2,306	2,707	2,040	2,021	3,084	3,783	3,852
16. Reserves (%) after Full Forced Outages (15/2) x 100	18.9	18.3	22.4	14.7	21.5	33.7	42.1	39.1
17. Other Unavailable Capability	148	152	187	116	31	98	46	12
18. Actual Capability (14-17)	14,130	14,730	14,608	15,809	11,393	12,142	12,718	13,681
19. Actual Reserves (18-2)	2,120	2,154	2,520	1,924	1,990	2,986	3,737	3,840
20. Actual Reserves (%) (19/2) x 100	17.7	17.1	20.8	13.9	21.2	32.6	41.6	39.0

Source: FPC Form 12E-2 and ERA-119M

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Table 8C.5

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
OKLAHOMA GROUP (REGION 22)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	18830	19225
2. PEAK DEMAND	14030	10011
3. PLANNED RESERVES (1-2)	4800	9214
4. PLANNED RESERVES (%) (3/2)X100	34.2	92.0
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-1424	-2029
6. TOTAL CAPABILITY (1+5)	17406	17196
7. TOTAL RESERVES (6-2)	3376	7185
8. TOTAL RESERVES (%) (7/2)X100	24.1	71.8
9. SCHEDULED MAINTENANCE 1/	0	2230
10. CAPABILITY AFTER MAINTENANCE (6-9)	17406	14966
11. RESERVES AFTER MAINTENANCE (10-2)	3376	4955
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	24.1	49.5
13. FULL FORCED OUTAGES 1/	527	634
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	16879	14332
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2849	4321
16. RESERVES (%) AFTER FULL-FORCED OUTAGES (15/2)X100	20.3	43.2
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	169	77
18. ACTUAL CAPABILITY (14-17)	16710	14255
19. ACTUAL RESERVES (18-2)	2680	4244
20. ACTUAL RESERVES (%) (19/2)X100	19.1	42.4

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

Table 8C.6

Projected Coal-fired Generating Units for the Period 1981-1990 as Projected April 1, 1981, to the Department of Energy

Oklahoma Group (Region 22)

Unit Name	Capability (MW)	As Reported April 1 1981	1980	Company
GRDA No. 1	490	7-81	7-81	Grand River Dam Authority
Hugo No. 1	376	3-82	3-82	Western Farmers Electric Coop.
Welsh No. 3	528	5-82	3-82	Southwestern Electric Power Co.
Tolk No. 1	508	6-82	6-82	Southwestern Public Service Co.
Muskogee No. 6	515	11-84	11-84	Oklahoma Gas & Electric Co.
Pirkey No. 1	640	3-85	3-85	Southwestern Electric Power Co.
Tolk No. 2	508	6-85	6-85	Southwestern Public Service Co.
Dolet Hills No. 1	640 1/	3-86	3-86	Southwestern Electric Power Co.
Oklaunion No. 1	640 2/	12-86	1-87	Public Service Co. of Oklahoma
Undetermined	500	5-88	5-87	Oklahoma Gas & Electric Co.
SPS CF6	600	6-89	6-87	Southwestern Public Service Co.
Unknown	500	5-90	5-89	Oklahoma Gas & Electric Co.
Total	6,445 3/			

1/ Joint ownership: Southwestern Electric Power Co. (50-percent) and Central Louisiana Electric Co. (50-percent) (Region 8).

2/ Joint ownership: Public Service Co. of Oklahoma (147 MW), Southwestern Electric Power Co. (50 MW), West Texas Utilities Co. (MW) (Region 23), and Central Power & Light Co. (115 MW) (Region 23).

3/ Of this total, 443 MW is allocated to ERCOT (Region 23) and 320 MW is allocated to MSU/Gulf (Region 8), leaving 5682 MW for Region 22.

Table 8C.7

Summer and Winter Capability by Fuel Type
(Megawatts)
1981-1990

Oklahoma Group
(Region 22)

Fuel Type	1981		1982		1983		1984		1985	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Coal	5,319	5,809	6,713	7,221	7,221	7,221	7,221	7,736	8,376	8,884
Oil	301	301	301	301	301	301	301	301	299	299
Gas	10,869	10,776	10,869	10,776	10,869	10,776	10,869	10,660	10,753	10,660
Nuclear	0	0	0	0	0	0	0	0	0	0
Hydro	2,341	2,339	2,341	2,339	2,341	2,339	2,341	2,339	2,341	2,339
Other	0	0	0	0	0	0	0	0	0	0
TOTAL	18,830	19,225	20,224	20,637	20,732	20,637	20,732	21,036	21,769	22,182

Fuel Type	1986		1987		1988		1989		1990	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Coal	9,204	9,204	9,401	9,401	9,901	9,901	9,901	10,501	11,001	11,001
Oil	299	299	299	299	295	295	295	295	295	295
Gas	10,753	10,660	10,698	10,605	10,698	10,306	10,369	10,095	10,170	10,077
Nuclear	0	0	0	0	0	0	0	0	0	0
Hydro	2,341	2,339	2,341	2,339	2,341	2,339	2,341	2,339	2,341	2,339
Other	0	0	0	0	0	0	0	0	0	0
TOTAL	22,597	22,502	22,739	22,644	23,235	22,841	22,906	23,230	23,807	23,712

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Table 8C.8

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1982-1985
OKLAHOMA GROUP (REGION 22)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	20224	20637	20732	20637	20732	21036	21769	22182
2. PEAK DEMAND	14687	10449	15261	10905	15845	11321	16416	11741
3. PLANNED RESERVES (1-2)	5537	10188	5471	9732	4887	9715	5353	10441
4. PLANNED RESERVES (%) (3/2)X100	37.7	97.5	35.8	89.2	30.8	85.8	32.6	88.9
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-1537	-2112	-1464	-1910	-1051	-1347	-1157	-1333
6. TOTAL CAPABILITY (1+5)	18687	18525	19268	18727	19681	19689	20612	20849
7. TOTAL RESERVES (6-2)	4000	8076	4007	7822	3836	8368	4196	9108
8. TOTAL RESERVES (%) (7/2)X100	27.2	77.3	26.3	71.7	24.2	73.9	25.6	77.6
9. SCHEDULED MAINTENANCE 1/	20	2394	21	2394	21	2440	22	2573
10. CAPABILITY AFTER MAINTENANCE (6-9)	18667	16131	19247	16333	19660	17249	20590	18276
11. RESERVES AFTER MAINTENANCE (10-2)	3980	5682	3986	5428	3815	5928	4174	6535
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	27.1	54.4	26.1	49.8	24.1	52.4	25.4	55.7
13. FULL FORCED OUTAGES 1/	566	681	580	681	580	694	610	732
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	18101	15450	18667	15652	19080	16555	19980	17544
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	3414	5001	3406	4747	3235	5234	3564	5803
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	23.2	47.9	22.3	43.5	20.4	46.2	21.7	49.4
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	182	83	187	83	187	84	196	89
18. ACTUAL CAPABILITY (14-17)	17919	15367	18480	15569	18893	16471	19784	17455
19. ACTUAL RESERVES (18-2)	3232	4918	3219	4664	3048	5150	3368	5714
20. ACTUAL RESERVES (%) (19/2)X100	22.0	47.1	21.1	42.8	19.2	45.5	20.5	48.7

COAL UNIT DELAYS ASSUMED POSSIBLE BY ERA

	1982 SUMMER	1982 WINTER	1983 SUMMER	1983 WINTER	1984 SUMMER	1984 WINTER	1985 SUMMER	1985 WINTER
21. POSSIBLE COAL DELAYS	528	0	0	0	0	0	0	0
22. ACTUAL CAPABILITY WITH COAL DELAYS (18-21)	17391	15367	18480	15569	18893	16471	19784	17455
23. ACTUAL RESERVES WITH COAL DELAYS (22-2)	2704	4918	3219	4664	3048	5150	3368	5714
24. ACTUAL RESERVES (%) WITH COAL DELAYS (23/2)X100	18.4	47.1	21.1	42.8	19.2	45.5	20.5	48.7

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

Table 8C.9

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1986-1990
OKLAHOMA GROUP (REGION 22)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	22597	22502	22739	22644	23235	22841	22906	23230	23807	23712
2. PEAK DEMAND	17004	12177	17615	12624	18261	13057	18889	13501	19500	13948
3. PLANNED RESERVES (1-2)	5593	10325	5124	10020	4974	9784	4017	9729	4307	9764
4. PLANNED RESERVES (%) (3/2)X100	32.9	84.8	29.1	79.4	27.2	74.9	21.3	72.1	22.1	70.0
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-1012	-1188	-1003	-1179	-1003	-1179	-1119	-1295	-1234	-1430
6. TOTAL CAPABILITY (1+5)	21585	21314	21736	21465	22232	21662	21787	21935	22573	22282
7. TOTAL RESERVES (6-2)	4581	9137	4121	8841	3971	8605	2898	8434	3073	8334
8. TOTAL RESERVES (%) (7/2)X100	26.9	75.0	23.4	70.0	21.7	65.9	15.3	62.5	15.8	59.8
9. SCHEDULED MAINTENANCE 1/	23	2610	23	2627	23	2650	23	2695	24	2751
10. CAPABILITY AFTER MAINTENANCE (6-9)	21562	18704	21713	18838	22209	19012	21764	19240	22549	19531
11. RESERVES AFTER MAINTENANCE (10-2)	4558	6527	4098	6214	3948	5955	2875	5739	3049	5583
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	26.8	53.6	23.3	49.2	21.6	45.6	15.2	42.5	15.6	40.0
13. FULL FORCED OUTAGES 1/	633	743	637	747	651	754	641	767	667	782
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	20929	17961	21076	18091	21558	18258	21123	18473	21882	18749
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	3925	5784	3461	5467	3297	5201	2234	4972	2382	4801
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	23.1	47.5	19.6	43.3	18.1	39.8	11.8	36.8	12.2	34.4
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	203	90	205	91	209	91	206	93	214	95
18. ACTUAL CAPABILITY (14-17)	20726	17871	20871	18000	21349	18167	20917	18380	21668	18654
19. ACTUAL RESERVES (18-2)	3722	5694	3256	5376	3088	5110	2028	4879	2168	4706
20. ACTUAL RESERVES (%) (19/2)X100	21.9	46.8	18.5	42.6	16.9	39.1	10.7	36.1	11.1	33.7

1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM 12E-2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

Table 8C.10

PROJECTED ENERGY AND DEMAND GROWTH RATES

Oklahoma Group
(Region 22)

Year	Energy Requirements (GWH)	Energy Requirements Growth (%)	Summer Peak Demand (MW)	Summer Peak Demand Growth (%)	Winter Peak Growth (MW)	Winter Peak Growth Growth (%)	Annual Load Factor (%)
1982	68,139	4.7	14,687	4.7	10,449	4.4	53.0
1983	71,194	4.5	15,261	3.9	10,905	4.4	53.3
1984	74,063	4.0	15,845	3.8	11,321	3.8	53.4
1985	77,119	4.1	16,416	3.6	11,741	3.7	53.6
% Growth 1982-85		4.3		4.0		4.1	
1986	80,400	4.3	17,004	3.6	12,177	3.7	54.0
1987	83,808	4.2	17,615	3.6	12,624	3.7	54.3
1988	87,487	4.4	18,261	3.7	13,057	3.4	54.7
1989	91,016	4.0	18,889	3.4	13,501	3.4	55.0
1990	94,776	4.1	19,500	3.2	13,948	3.3	55.5
% Growth 1986-90		4.2		3.5		3.5	
% Growth 1982-90		4.3		3.7		3.8	

SECTION XIV.9
WESTERN SYSTEMS COORDINATING COUNCIL
(WSCC)

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Western Systems Coordinating Council (WSCC)

Introduction

The Western Systems Coordinating Council (WSCC) was organized in 1967 to promote bulk power system reliability through coordinated planning and operation. Present membership includes 48 member systems and 14 affiliate members. These utility systems provide substantially all of the electric service in the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming, as well as portions of South Dakota, Texas, and the Canadian Provinces of Alberta and British Columbia. This report covers only the United States portion of the WSCC.

The WSCC consists of five subregions or Areas. Electric Regions identified in this chapter are consistent with the WSCC Areas but may differ slightly from the DOE Electric Regions. Identification of reporting utilities within the respective regions is included in Appendix B.

Table 9.1

Electic Regions Within WSCC

WSCC Area	Electric Region
Rocky Mountain	24
Northwest Power Pool	25
Arizona - New Mexico	26
Southern California - Nevada	27
Northern California - Nevada	28

WSCC abuts the Mid-Continent Area Power Pool, the Southwest Power Pool, and the Electric Reliability Council of Texas to the east; Mexico to the south; and Canada to the north.

The following sections are comprised of a brief definition of each of the WSCC Areas, and historical, current and future perspectives of electric power supply and demand conditions within each area. Tables for each area include data on loads, resources and reserve margins extracted from the WSCC ERA-411 Report submitted in April 1981. Estimates of fuel consumption by type of generation were taken from the WSCC report, "Summary of Estimated Loads and Resources."

A. Rocky Mountain Power Area (RMPA)

Electric Region 24

The Rocky Mountain Power Area (RMPA) encompasses the entire state of Colorado, the eastern half of Wyoming, and a portion of southwestern South Dakota. Major utilities in the region include: Public Service Company of Colorado (PSCC) which serves more than 50 percent of the region's electric demand; DOE Western Area Power Administration (WAPA) which serves various public utilities within and outside the region; Colorado-Ute Electric Association (CUEA); City of Colorado Springs (CCS); Tri-State Generation and Transmission Association (TSG&T); and Black Hills Power and Light Company (BHP&L) serving loads in eastern Wyoming and soutnwestern South Dakota.

[redacted]

Historical Perspective

Electric demand is nearly constant in winter and summer, and in recent years the region has experienced annual peaks during both seasons. The 1980 peak demand occurred in August. Table 9A.1 shows the actual loads experienced during 1980.

Table 9A.1

1980 Load Growth
Rocky Mountain Power Area

	1980
Energy Load (GwH)	29479
Growth rate from 1979 (%)	6.4
Peak Demand (MW)	5137
Growth rate from 1979 (%)	5.8
Load Factor (%)	65.5

As shown in Table 9A.2, the predominant type of generating capability in the region is coal-fired steam generation which amounted to 3789 MW of capacity and represented 51.1 percent of total capability and 56.8 percent of total generation in 1980. Within the region, a significant amount of hydroelectric capability exists totalling about 32 percent of the installed capability and accounting for 29.2 percent of total energy generation in 1980. The majority of this hydro capacity is owned and operated by the U.S. Water and Power Resources Service and marketed by WAPA's Upper Colorado and Lower Missouri Regions. The sole nuclear generating plant in the region is the 330 MW Fort St. Vrain high temperature gas reactor which is currently limited to 200 MW capability due to an NRC restriction. Table 9A.3 shows the actual peak load, supply and reserve margins for the 1980 summer peak period and, for comparison, the forecasted conditions as compiled a year ago.

Within the RMPA there remain significant transmission bottlenecks which plague systems' reliability and cause curtailments of coal-fired generation. Transmission limitations, particularly from western to eastern Colorado, continue due to delays of needed line additions.

Completion of the 175 mile, 230 KV (operating voltage) line, from the Laramie River Station to northeastern Colorado in 1980 has alleviated the limitation on import capability from Wyoming.

Current Perspective

Reserve margins in the Rocky Mountain Power Area are expected to be more than adequate for 1981. However, the aforementioned transmission deficiencies may again cause reliability problems in Colorado. Appendix C contains a further analysis of the 1981 summer conditions. Annual energy load for the region is forecast to increase by 4.8 percent in 1981 over that for 1980.

During 1981, scheduled additions to generating capacity consist of 470 MW of coal-fired capacity, 206 MW of pumped storage capacity (winter capability), and 4 MW of wind-powered capacity (see Table 9A.7).

[redacted]

Future Perspective

Utilities in the region forecast summer peak demand to increase an average of 6.1 percent per year from 1981 through 1985 and 5.2 percent per year from 1986 through 1990. Energy growth is projected to average 6.9 percent annually through 1985 and 5.2 percent per year from 1986 through 1990. Load factors are expected to increase from 64.6 percent in 1981 to 68.4 percent in 1990 (see Table 9A.6).

Table 9A.8 lists the major additions to generating capacity, as currently planned, and the delay from the schedule of a year ago. Additionally, 1510 MW of coal-fired and 1284 MW of hydro capacity have been cancelled or delayed to beyond 1990 since last year.

Coal-fired additions remain the most significant component of the present schedule totalling 4350 MW through 1990 and accounting for about 67 percent of the total generating capability of the region (see Table 9A.7). Tables 9A.9 and 9A.10 show the summer and winter capabilities by type in total megawatts and percent of total capability for 1981 through 1990.

The estimated operation and fuel consumption for 1985 and 1990 are presented in Tables 9A.11 and 9A.12 indicating the expected threefold increase in coal use over 1980 and a corresponding reduction in the use of equivalent barrels of oil and natural gas for the decade.

Tables 9A.13 and 9A.14 show the expected reserve margins for 1982 through 1990 including the effects on actual reserves of an assumed 6-month delay of all scheduled coal-fired units. Reserve margins remain adequate under all circumstances.

Significant transmission additions totalling 1105 miles of 230 KV line and 1681 miles of 345 KV line are planned for the region through 1990, thus increasing the total number of circuit miles by more than 30 percent from the existing grid. These additions are designed to transport power from new generating units as well as to eliminate existing transmission inadequacies. Continued delays in building these facilities could result in a continuation of past reliability problems and possible additional consumption of natural gas and oil.

Table 9A.2

ACTUAL 1980 OPERATION BY TYPE OF PLANT
Rocky Mountain Power Area

Plant Type	Fuel Type	Capability (as of 12-31-80) MW	Capability (as of 12-31-80) % of Total	Annual Energy GWH	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	2087	28.1	8913	28.7	-
Hydro Pumped Storage	Water	269	3.6	158	0.5	-
Steam	Coal	3789	51.1	17643	56.8	10050 Tons
Steam	Oil	368	5.0	53	0.2	132 bbls
Steam	Gas	-	-	2116	6.8	26201 MCF
Steam	Nuclear	200	2.7	675	2.2	-
Combustion Turbine	Oil	167	9.0	121	0.4	279 bbls
Combustion Turbine	Gas	-	-	429	1.4	5455 MCF
Combined Cycle	Oil	0	0	0	0	0
Combined Cycle	Gas	0	0	0	0	0
Geothermal	GST	0	0	0	0	-
Internal Combustion	Oil	41	0.6	4	-	7 bbls
Cogeneration		0	0	0	0	0
Other		0	0	969	3.1	-
Total		7421	100.0	31081	100.0	

Total Fuel Consumption

Coal (tons x 1000)		10050
Gas (MCF x 1000)		31656
Gas (equivalent oil bbls x 1000)		5381
Oil: distillate (bbls x 1000)	418	
residual	0	
crude	0	
Total oil		418

[redacted]

Table 9A.3

ACTUAL CAPABILITY (MW) AND RESERVES (MW and Percent) - 1980
Rocky Mountain Power Area (Region 24)

	Forecast Summer 1980	Actual Summer 1980
1. Planned Capability	7302	7103
2. Peak Demand	5297	5137
3. Planned Reserves (1-2)	2005	1966
4. Planned Reserves (%) (3/2) x100	37.9	38.3
5. Net Transactions (Imports - Exports)	-474	-437
6. Total Capability (1+5)	6828	6666
7. Total Reserves (6-2)	1531	1529
8. Total Reserves (%) (7/2) x100	28.9	29.8
9. Scheduled Maintenance	0	30
10. Capability After Maintenace (6-9)	6828	6636
11. Reserves After Maintenance (10-2)	1531	1499
12. Reserves After Maintenance (%) (11/2) x100	28.9	29.2
13. Full Forced Outage	273	324
14. Capability After Forced Outage (10-13)	6555	6312
15. Reserves After Forced Outage (14-2)	1258	1175
16. Reserves After Forced Outage (%) (15/2) x100	23.7	22.9
17. Other Unavailable Capability	68	1
18. Actual Capability (14-17)	6487	6311
19. Actual Reserves (18-2)	1190	1174
20. Actual Reserves (%) (19/2) x100	22.5	22.9

Table 9A.4

ESTIMATED 1981 OPERATION BY TYPE OF PLANT

Rocky Mountain Power Area

Plant Type	Fuel Type	Capability (as of August 1981) MW	Capability (as of August 1981) % of Total	Annual Energy GWH	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	2141	28.7	8273	25.4	-
Hydro Pumped Storage	Water	262	3.5	221	0.7	-
Steam	Coal	3899	52.2	21959	67.4	12965 tons
Steam	Oil	381	5.1	96	0.3	256 bbls
Steam	Gas	-	-	1059	3.3	15064 MCF
Steam	Nuclear	200	2.7	633	1.9	-
Combustion Turbine	Oil	534	7.1	40	0.1	85 bbls
Combustion Turbine	Gas	-	-	266	0.8	3288 MCF
Combined Cycle	Oil	0	0	0	0	0
Combined Cycle	Gas	0	0	0	0	0
Geothermal	GST	0	0	0	0	0
Internal Combustion	Oil	53	0.7	9	-	20 bbls
Fuel Cell		0	0	0	0	-
Other		0	0	0	0	-
Total		7470	100.0	32556	100.0	

Total Fuel Consumption

Coal (tons x 1000)		12965
Gas (MCF x 1000)		18352
Gas (equivalent oil bbls x 1000)		3119
Oil: distillate (bbls x 1000)	361	
residual	0	
crude	0	
Total oil		361

Table 9A.5

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
ROCKY MOUNTAIN POWER POOL AREA (REGION 20)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	7845	9371
2. PEAK DEMAND	5338	5462
3. PLANNED RESERVES (1-2)	2507	2909
4. PLANNED RESERVES (%) (3/2)X100	47.0	53.3
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-951	-845
6. TOTAL CAPABILITY (1+5)	6894	7526
7. TOTAL RESERVES (6-2)	1556	2064
8. TOTAL RESERVES (%) (7/2)X100	29.1	37.8
9. SCHEDULED MAINTENANCE 1/	25	360
10. CAPABILITY AFTER MAINTENANCE (6-9)	6869	7166
11. RESERVES AFTER MAINTENANCE (10-2)	1531	1704
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	28.7	31.2
13. FULL FORCED OUTAGES 1/	149	100
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	6720	7066
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1382	1604
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	25.9	29.4
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	243	243
18. ACTUAL CAPABILITY (14-17)	6477	6823
19. ACTUAL RESERVES (18-2)	1139	1361
20. ACTUAL RESERVES (%) (19/2)X100	21.3	24.9

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Table 9A.6

PROJECTED ENERGY AND DEMAND GROWTH RATES
Rocky Mountain Power Area

	Energy Requirements		Summer Peak Demand		Winter Peak Demand		Annual Load Factor
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	(%)
1981	30903	4.8	5338	3.9	5462	7.5	64.6
1982	33576	8.6	5722	7.2	5859	7.3	65.4
1983	36420	8.5	6112	6.8	6228	6.3	66.8
1984	38542	5.8	6471	5.9	6527	4.8	67.4
1985	40372	4.7	6771	4.6	6916	6.0	66.6
% Growth 1981-1985		6.9		6.1		6.1	
1986	42567	5.4	7114	5.1	7302	5.6	66.5
1987	44971	5.6	7515	5.6	7742	6.0	66.3
1988	47278	5.1	7907	5.2	8120	4.9	66.5
1989	49703	5.1	8294	4.9	8583	5.7	66.1
1990	52180	5.0	8707	5.0	8591	0.1	68.4
% Growth 1986-1990		5.2		5.2		4.1	
% Growth 1981-1990		6.0		5.6		5.2	

Table 9A.7

SUMMARY OF GENERATION ADDITIONS AND CHANGES

Rocky Mountain Power Area

(Winter Capability - MW)

Generation Type	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	10-Yr. Period	% of Total
Hydro-Conventional		12	24	6	3	77					122	2.5%
Hydro Pumped Storage	206		100								306	6.3%
Steam-Coal	470	550	400	250		470	400	590	400	820	4350	89.5%
Steam-Gas and Oil						-18					-18	-.4%
Nuclear												0%
Combustion Turbine												0%
Combined Cycle												0%
Geothermal												0%
Internal Combustion												0%
Cogeneration												0%
Other	4				100						104	2.1%
Total	680	562	524	256	103	529	400	590	400	820	4864	100.0%

[redacted]

Table 9A.8

PLANNED SIGNIFICANT ADDITIONS TO GENERATING CAPACITY
Rocky Mountain Power Area

Unit Name & Number	Type	Capability (MW)	Scheduled In-service Date	Delay Since Last Year (Months)[1]
Mount Elbert 1	Pumped Storage	100	7/81	
Cabin Creek	Pumped Storage	+ 106	7/81	
Pawnee 1	Coal	470	12/81	11
Laramie River Station 3	Coal	550	4/82	
Mount Elbert 2	Pumped Storage	100	8/83	
Craig 3	Coal	400	10/83	3
Rawhide 1	Coal	250	4/84	
Wind Farm	Wind	100	12/85	
Southeast 1	Coal	470	4/86	12
Southwest 1	Coal	400	10/87	- 12 [2]
Ray D. Nixon 2	Coal	590	4/88	4
Southwest 2	Coal	400	4/89	
Southeast 2	Coal	470	4/90	45
Tri-State	Coal	350	4/90	

1/ Number of months, if any, that the unit has been delayed from the schedule in the 1980 Electric Power Supply and Demand Report.

2/ Indicates an acceleration in planned construction schedule.

Table 9A.9

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Rocky Mountain Power Area

Summer Capability

			Oil and Gas						Hydro 2/		
	Nuclear Steam	Coal Steam	Steam	Combined Cycle	Combust. Turbine	Geo-Thermal	Cogen-eration	Other 1/	Conven-tional	Pumped Storage	Total Capability
1981	200	3899	381	0	534	0	0	53	2141	262	7470
% Total	2.7	52.2	5.1	0.0	7.1	0.0	0.0	0.7	28.7	3.5	
1982	200	4731	348	0	534	0	0	53	2141	262	8269
% Total	2.4	57.2	4.2	0.0	6.5	0.0	0.0	0.6	25.7	3.2	
1983	200	4952	348	0	534	0	0	53	2157	362	8606
% Total	2.3	57.5	4.0	0.0	6.2	0.0	0.0	0.6	25.1	4.2	
1984	200	5651	337	0	534	0	0	53	2181	362	9318
% Total	2.1	60.6	3.6	0.0	5.7	0.0	0.0	0.6	23.4	3.9	
1985	200	5700	348	0	534	0	0	153	2181	362	9478
% Total	2.1	60.1	3.7	0.0	5.6	0.0	0.0	1.6	23.0	3.8	
1986	275	6130	348	0	534	0	0	153	2184	362	9986
% Total	2.8	61.4	3.5	0.0	5.3	0.0	0.0	1.5	21.9	3.6	
1987	275	6192	348	0	534	0	0	153	2206	362	10070
% Total	2.7	61.5	3.5	0.0	5.3	0.0	0.0	1.5	21.9	3.6	
1988	275	7182	348	0	534	0	0	153	2206	362	11060
% Total	2.5	64.9	3.1	0.0	4.8	0.0	0.0	1.4	19.9	3.3	
1989	275	7582	348	0	534	0	0	153	2206	362	11460
% Total	2.4	66.2	3.0	0.0	4.7	0.0	0.0	1.3	19.2	3.2	
1990	275	8362	348	0	553	0	0	153	2206	362	12259
% Total	2.2	68.2	2.8	0.0	4.5	0.0	0.0	1.2	18.0	3.0	

1/ Other capability includes wind and oil-fired diesel generation (53 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

Table 9A.10

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Rocky Mountain Power Area

Winter Capability

	Nuclear Steam	Coal Steam	Oil and Gas Steam	Oil and Gas Combined Cycle	Oil and Gas Combust. Turbine	Geo-Thermal	Cogen-eration	Other 1/	Hydro 2/ Conven-tional	Hydro 2/ Pumped Storage	Total Capability
1981	200	4373	340	0	654	0	0	53	2087	368	8075
% Total	2.5	54.2	4.2	0.0	8.1	0.0	0.0	0.7	25.8	4.6	
1982	200	4813	340	0	654	0	0	53	2095	368	8523
% Total	2.3	56.5	4.0	0.0	7.7	0.0	0.0	0.6	24.6	4.3	
1983	200	5405	340	0	654	0	0	53	2119	468	9239
% Total	2.2	58.5	3.7	0.0	7.1	0.0	0.0	0.6	22.9	5.1	
1984	200	5655	340	0	654	0	0	153	2125	468	9595
% Total	2.1	58.9	3.5	0.0	6.8	0.0	0.0	1.6	22.1	4.9	
1985	200	5704	340	0	654	0	0	153	2128	468	9647
% Total	2.1	59.1	3.5	0.0	6.8	0.0	0.0	1.6	22.1	4.9	
1986	275	6176	340	0	654	0	0	153	2150	468	10236
% Total	2.7	60.5	3.3	0.0	6.4	0.0	0.0	1.5	21.0	4.6	
1987	275	6506	340	0	654	0	0	153	2150	468	10546
% Total	2.6	61.7	3.2	0.0	6.2	0.0	0.0	1.5	20.4	4.4	
1988	275	7156	340	0	654	0	0	153	2150	468	11226
% Total	2.4	64.0	3.0	0.0	5.8	0.0	0.0	1.4	19.2	4.2	
1989	275	7586	389	0	667	0	0	153	2150	468	11688
% Total	2.4	64.9	3.3	0.0	5.7	0.0	0.0	1.3	18.4	4.0	
1990	275	8366	389	0	667	0	0	153	2150	468	12468
% Total	2.2	67.1	3.1	0.0	5.3	0.0	0.0	1.2	17.7	3.8	

1/ Other capability includes wind and oil-fired diesel generation (53 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

Table 9A.11

ESTIMATED 1985 OPERATION BY TYPE OF PLANT

Rocky Mountain Power Area

Plant Type	Fuel Type	Capability (as of August 1985) MW	Capability (as of August 1985) % of Total	Annual Energy GWH	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	2181	23.0	8656	19.8	-
Hydro Pumped Storage	Water	362	3.8	357	0.8	-
Steam	Coal	5700	60.1	32491	14.3	19445 tons
Steam	Oil	348	3.7	285	0.7	433 bbls
Steam	Gas	-	-	647	1.5	9913 MCF
Steam	Nuclear	200	2.1	701	1.6	-
Combustion Turbine	Oil	534	5.6	357	0.8	733 bbls
Combustion Turbine	Gas	-	-	250	0.6	3117 MCF
Combined Cycle	Oil	0	0	0	0	0
Combined Cycle	Gas	0	0	0	0	0
Geothermal	GST	0	0	0	0	0
Internal Combustion	Oil	53	0.6	10	-	20 bbls
Fuel Cell	- -	0	0	0	0	-
Other	- -	100	1.1	0	0	-
Total		9478	100.0	43754	100.0	

Total Fuel Consumption

Coal (tons x 1000)		19445
Gas (MCF x 1000)		13030
Gas (equivalent oil bbls x 1000)		2215
Oil: distillate (bbls x 1000)	946	
residual	240	
crude	0	
Total oil		1186

Table 9A.12

ESTIMATED 1990 OPERATION BY TYPE OF PLANT

Rocky Mountain Power Area

Plant Type	Fuel Type	Capability (as of August 1990) MW	Capability (as of August 1990) % of Total	Annual Energy GWH	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	2206	18.0	8658	15.6	-
Hydro Pumped Storage	Water	362	3.0	315	0.6	-
Steam	Coal	8362	68.2	44785	80.9	28267 tons
Steam	Oil	348	2.8	136	0.2	161 bbls
Steam	Gas	-	-	598	1.1	10299 MCF
Steam	Nuclear	275	2.2	701	1.3	-
Combustion Turbine	Oil	553	4.5	47	0.1	99 bbls
Combustion Turbine	Gas	-	-	107	0.2	1349 MCF
Combined Cycle	Oil	0	0	0	0	0
Combines Cycle	Gas	0	0	0	0	0
Geothermal	GST	0	0	0	0	0
Internal Combustion	Oil	53	0.4	9	-	18 bbls
Fuel Cell		0	0	0	0	-
Other		100	0.8	0	0	-
Total		12259	100.0	55356	100.0	

Total Fuel Consumption

Coal (tons x 1000)		28267
Gas (MCF x 1000)		11648
Gas (equivalent oil bbls x 1000)		1980
Oil: distillate (bbls x 1000)	278	
residual	0	
crude	0	
Total oil		278

Table 9A.13

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1982-1985
ROCKY MOUNTAIN POWER POOL AREA (REGION 24)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	8515	8769	8852	9436	9515	9792	9626	9795
2. PEAK DEMAND	5722	5859	6112	6228	6471	6527	6771	6916
3. PLANNED RESERVES (1-2)	2793	2910	2740	3208	3044	3265	2855	2879
4. PLANNED RESERVES (%) (3/2)X100	48.8	49.7	44.8	51.5	47.0	50.0	42.2	41.6
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-975	-889	-965	-808	-922	-801	-889	-754
6. TOTAL CAPABILITY (1+5)	7540	7880	7887	8628	8593	8991	8737	9041
7. TOTAL RESERVES (6-2)	1818	2021	1775	2400	2122	2464	1966	2125
8. TOTAL RESERVES (%) (7/2)X100	31.8	34.5	29.0	38.5	32.8	37.8	29.0	30.7
9. SCHEDULED MAINTENANCE 1/	102	377	106	406	114	421	116	421
10. CAPABILITY AFTER MAINTENANCE (6-9)	7438	7503	7781	8222	8479	8570	8621	8620
11. RESERVES AFTER MAINTENANCE (10-2)	1716	1644	1669	1994	2008	2043	1850	1704
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	30.0	28.1	27.3	32.0	31.0	31.3	27.3	24.6
13. FULL FORCED OUTAGES 1/	162	105	168	113	181	118	183	118
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	7276	7398	7613	8109	8298	8452	8438	8502
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1554	1539	1501	1881	1827	1925	1667	1586
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	27.2	26.3	24.6	30.2	28.2	29.5	24.6	22.9
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	264	254	274	274	295	284	298	284
18. ACTUAL CAPABILITY (14-17)	7012	7144	7339	7835	8003	8168	8140	8218
19. ACTUAL RESERVES (18-2)	1290	1285	1227	1607	1532	1641	1369	1302
20. ACTUAL RESERVES (%) (19/2)X100	22.5	21.9	20.1	25.8	23.7	25.1	20.2	18.8

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. POSSIBLE COAL DELAYS	550	0	0	449	250	0	49	0
22. ACTUAL CAPABILITY WITH COAL DELAYS (18-21)	6462	7144	7339	7386	7753	8168	8091	8218
23. ACTUAL RESERVES WITH COAL DELAYS (22-2)	740	1285	1227	1158	1282	1641	1320	1302
24. ACTUAL RESERVES (%) WITH COAL DELAYS (23/2)X100	12.9	21.9	20.1	18.6	19.8	25.1	19.5	18.8

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Table 9A.14
FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1986-1990
ROCKY MOUNTAIN POWER POOL AREA (REGION 24)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	10134	10322	10156	10632	11146	11312	11546	11774	12345	12554
2. PEAK DEMAND	7114	7302	7515	7742	7907	8120	8294	8583	8707	8591
3. PLANNED RESERVES (1-2)	3020	3020	2641	2890	3239	3192	3252	3191	3638	3963
4. PLANNED RESERVES (%) (3/2)X100	42.5	41.4	35.1	37.3	41.0	39.3	39.2	37.2	41.8	46.1
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-894	-688	-828	-684	-824	-681	-821	-677	-814	-687
6. TOTAL CAPABILITY (1+5)	9240	9634	9328	9948	10322	10631	10725	11097	11531	11867
7. TOTAL RESERVES (6-2)	2126	2332	1813	2206	2415	2511	2431	2514	2824	3276
8. TOTAL RESERVES (%) (7/2)X100	29.9	31.9	24.1	28.5	30.5	30.9	29.3	29.3	32.4	38.1
9. SCHEDULED MAINTENANCE 1/	122	444	122	497	134	486	139	506	148	540
10. CAPABILITY AFTER MAINTENANCE (6-9)	9118	9190	9206	9451	10188	10145	10586	10591	11383	11327
11. RESERVES AFTER MAINTENANCE (10-2)	2004	1888	1691	1749	2281	2025	2292	2008	2676	2736
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	28.2	25.9	22.5	22.6	28.8	24.9	27.6	23.4	30.7	31.8
13. FULL FORCED OUTAGES 1/	193	124	193	128	212	136	219	141	235	151
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	8925	9066	9013	9363	9976	10009	10367	10450	11148	11176
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1811	1764	1498	1621	2069	1889	2073	1867	2441	2585
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	25.5	24.2	19.9	20.9	26.2	23.3	25.0	21.8	28.0	30.1
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	314	299	315	308	346	328	358	341	383	364
18. ACTUAL CAPABILITY (14-17)	8611	8767	8698	9055	9630	9681	10009	10109	10765	10812
19. ACTUAL RESERVES (18-2)	1497	1465	1183	1313	1723	1561	1715	1526	2058	2221
20. ACTUAL RESERVES (%) (19/2)X100	21.0	20.1	15.7	17.0	21.8	19.2	20.7	17.8	23.6	25.9

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. POSSIBLE COAL DELAYS	430	62	0	400	590	0	400	0	630	0
22. ACTUAL CAPABILITY WITH COAL DELAYS (18-21)	8181	8705	8698	8655	9040	9681	9609	10109	10135	10812
23. ACTUAL RESERVES WITH COAL DELAYS (22-2)	1067	1403	1183	913	1133	1561	1315	1526	1428	2221
24. ACTUAL RESERVES (%) WITH COAL DELAYS (23/2)X100	15.0	19.2	15.7	11.8	14.3	19.2	15.9	17.8	16.4	25.9

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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B. Northwest Power Pool Area

Electric Region 25

The Northwest Power Pool Area (NWPP) includes 18 member systems and 4 affiliate members which voluntarily operate on a coordinated basis. As aforementioned, Canadian systems are not included in this analysis. A complete listing of members and other organizations within the NWPP Region is in Appendix B. The region encompasses the states of Washington, Oregon, Idaho, Utah, most of Montana and parts of Wyoming, Nevada, and a small part of Northern California. Originally, the pool was divided into an East Group and West Group; however, increased interconnections between the two groups resulted in designation of the area as one entity. The Pacific Northwest Utilities Conference Committee (PNUCC), an outgrowth of the Northwest Power Pool, maintains the designation of the West Group area. The PNUCC coordinates regional power planning and provides support for the Federal Marketing Agency for electric power owned by the U.S. Corps of Engineers and U.S. Water and Power Resources Services.

Historical Perspective

The Northwest Power Pool Area has a pronounced peak that is heavily influenced by a significant saturation of electric heating loads. Annual energy growth rates of nearly 7 percent were prevalent during the 1960's. However, this changed significantly in the early 1970's. A general downturn in the economy, the 1973 oil embargo, a drought, and resultant effects of customer conservation reduced average energy growth rates to about 3.8 percent per year. The conservation theme plus other load reduction efforts extended into the 1980's resulting in a continued lowering of the growth rate.

Since the area is heavily dependent on hydroelectric generation, power supply is acutely affected by annual precipitation. Hydroelectric reservoir storage in the Pacific Northwest (West Group) was essentially full at the end of the 1980 summer season. Water conditions continued to be favorable at the end of 1980 entering the winter peak season. As a result, Bonneville Power Administration (BPA) began selling secondary energy outside the region. All utilities in the region were notified they could either shut down or minimize thermal generation. BPA served notification it would replace all thermal energy and load the Pacific Northwest - Pacific Southwest Transmission Intertie to capacity. Simultaneously, Columbia River plants began spilling accumulated water storage. This situation continued through 1980. It was the third time in the 12-year history of the Pacific Intertie that BPA has sold secondary energy in December.

Loads for 1980 continued to be lower than those forecasted. Annual energy consumption for 1980 decreased 0.2 percent from 1979. Actual load requirements for 1979, including annual growth rate and load factor, are shown in the following table.

Table 9B.1

1980 Load Growth

Northwest Power Pool Area

	1980
Annual Electric Energy (Gwh)	172857
Growth Rate from 1979 (%)	-0.2
Winter Peak Demand (MW)	34092 1/
Growth Rate from 1979 (%)	4.0
Load Factor (%)	57.9

1/ Estimated for January 1981.

[redacted]

Table 9B.2 shows actual generation by type of plant and fuel consumption for 1980. In 1980, hydroelectric generation supplied 70.8 percent of the total generation with coal-fired plants providing 24.0 percent of the total generation. Presently, there is one nuclear generating plant operating in the region: Trojan (1080 MW), operated by Portland General Electric Company (PGE). For planning purposes, the Hanford, Washington, Nuclear Power Reactor facility is not considered dependable. However, energy generated by the Hanford plant is included in Table 9B.2. The remainder of the region's electric power supply emanates from gas/oil-fired plants -- approximately 1.0 percent. Within the area, a total of 8.6 million MCF of natural gas was burned in 1980 -- equivalent to 1.47 million barrels of oil. Actual oil consumption was 354 thousand barrels. These amounts represent a decrease of 48.6 percent from 1979 oil/gas consumption.

Generally, high capacity reserve margins occur during the summer peak season. Excess summer capacity and associated energy serves secondary markets and interruptible loads. Historically, summer and winter capacity reserve margins have been sufficient in the Northwest Power Pool Area.

Table 9B.3 shows summer and winter peak demands, resources, and reserve margins for the years 1979 and 1980. The projection for 1980 summer peak demand was 2,435 MW (9.4%) under what was forecasted. 1980-81 actual winter peak data has not been reported by WSCC. However, a calculation of the actual winter peak, based on ERA-Form 119 data, indicates the peak demand occurred in February 1981 and was 30,352 MW. Thus, it appears that the actual 1980-81 winter peak was 3,740 MW (11.0%) under the latest WSCC estimate.

Current Perspective

The 1981-82 winter peak demand is estimated to increase 1.3 percent over the previous winter season. Annual 1981 energy requirements are forecasted to increase by 12.5 percent over 1980. During the winter season of 1980-81, adjusted monthly energy loads were consistently lower than those forecasted. The Northwest Power Pool Coordinating Group's monthly reports state that for the first quarter of 1981, monthly electric energy consumption was between 0.6 percent and 3.0 percent higher than corresponding months in the previous year.

Updated forecasts project that the Columbia River January - July runoff should be adequate to refill all major reservoirs in the region. With these favorable hydro conditions at the start of the water year, the winter hydro capability is then dependent on precipitation during the months immediately preceding the winter peak.

Capacity additions scheduled to be placed in service for 1981 total 840 MW. Included in this amount are 334 MW of conventional hydroelectric capacity, 150 MW of pumped storage hydro and 356 MW of combustion turbines. The four units of combustion turbines to be installed by Puget Sound Power and Light Company will burn natural gas as a primary fuel. Estimated 1981 operation by type of plant and fuel use under median hydro conditions is shown in Table 9B.4.

Table 9B.5 shows projected loads and reserve margins for the 1981 summer and winter peak periods. An assessment of the 1981 summer load supply situation is included in Appendix C. Since the region's annual peak occurs during the winter season, this analysis will be concerned with the upcoming winter peak period. As shown in Table 9B.5, the 1981-82 winter total reserves are projected to be 11.1 percent and are considered sufficient to meet Criterion 1 of the WSCC "Power Supply Design Criteria." Also included in this table is the estimated effect of outages based on a 3-year historical average. Considering these possible outages, the region could have actual reserves reduced to inadequate levels under adverse water conditions. However, during periods of short power supply, some scheduled maintenance could be deferred; and BPA's interruptible load of approximately 1000 MW, which is included in its firm load for planning purposes, could be curtailed.

Future Perspective

The Northwest Power Pool Area loads are projected to increase at an average annual rate of 4.2 percent for winter peak demand and 3.9 percent for annual energy use during the 1981-85 period. This average annual energy growth rate is slightly lower than the 4.1 percent experienced during the 1977-80 period. The winter peak forecast for 1985 has been reduced by 1221 MW or 2.9 percent from the April 1980 ERA-411 report. The 1985 energy forecast has been reduced by 10,153 Gwh or 4.3 percent. For the years 1986 through 1990, the estimated average annual growth rate for peak demand is 2.6 percent while energy use is estimated to increase at a 3.4 percent annual rate. Table 9B.6 shows projected energy and peak demand growth rates from 1981 to 1990. Although growth rates are projected to decline, total growth is forecasted to be substantial. From 1980 to 1990, energy use is estimated to increase by 96,671 Gwh (55.9 percent) to 269,528 Gwh. Peak demand is projected to increase by 16,594 MW (55.2 percent) to 46,639 for the same period.

Table 9B.7 summarizes annual generating capacity additions and changes for the 10-year period 1981 through 1990. Table 9B.8 lists the scheduled major unit additions and estimated in-service dates.

A newly reported unit in this report is the 1000 MW, 2 unit, Creston coal-fired project. The project is proposed by Washington Water Power Company, and the first unit (500 MW) is estimated to be in service in July 1987.

Additions to generating capacity for the region total 5,273 MW for the period 1981 through 1985. The scheduled additions include 2200 MW of coal-fired and 1100 MW of nuclear generating capacity. The Hanford Nuclear Power Reactor steam project, 840 MW, is scheduled to be retired in June of 1983. The project depends on the operation of a plutonium production reactor and is not considered dependable for resource planning purposes. For the period 1986 through 1990, a total of 9,898 MW is planned for addition to the region's generating capability. A portion of that capability is from the proposed Intermountain coal project -- 316 MW (42.1%) of each of four units will be shared by Utah utilities with the remainder owned by Southern California utilities.

There have been several delays in the projected commercial operation dates of generating units since the July 1980 issuance of this report. The delayed units and the number of months of delay are listed in Table 9B.8.

Tables 9B.9 and 9B.10 show the estimated operation by type of plant and fuel use for 1985 and 1990. Under median hydro conditions, estimated oil/gas-fired generation will supply only 1.6 percent of the total generation in 1985 and 0.5 percent in 1990. Planned net capability by type of plant for 1981 through 1990 is listed in Tables 9B.11 and 9B.12. Nuclear plant capability is projected to increase its share of the total generating capability to 13.1 percent by 1990 while hydroelectric capability is expected to decline to 57.6 percent.

The NWPP is heavily dependent upon hydroelectric generation and, although generating capacity at peak load times may be adequate, energy supplies may be deficient in the region. To date, delays in generating unit installations have produced only small deficiencies during peak load conditions. However, peak time reserve margins are projected to decrease and energy deficits are projected to increase significantly as additional generating units are delayed.

The estimated capacity reserve margins for the Northwest Power Pool Area for 1982-1990 are indicated in Tables 9B.13 and 9B.14. Considering the effects of possible outages and adverse water conditions, there could be inadequate capability during the 1982-85 winter peak seasons. However, if median water conditions exist and BPA's interruptible load of approximately 1000 MW is used for reserve, this situation could be improved. Normally, some scheduled maintenance could be deferred during power suply shortage situations. In addition, for purposes of this report, a delay of 12 months for nuclear units and 6 months for coal-fired units was assumed by Staff to assess the effects on reserve margins. Tables 9B.13 and 9B.14 show the estimated actual reserve margins considering these delays.

[redacted]

The Colstrip - Hot Springs, Montana, 500 KV transmission system, which is partially owned by Montana Power Company and Bonneville Power Administration, consists of two 500 KV lines (453 miles) associated with Colstrip Units No's. 3 and 4. The installation of these lines has been delayed from May 1978 and May 1979 until January 1984 and July 1985, respectively, due to regulatory and court actions. The delay could adversely affect the reliability of the interconnected system in the Northwest Power Pool Region.

The Regional Power Act

One of the most important pieces of energy legislation to be approved by Congress for the Northwest in many years was enacted on December 5, 1980. This Act, entitled "The Pacific Northwest Electric Power Planning and Conservation Act," will have far-reaching effects on the future power supply in the Pacific Northwest. The Act expands the Bonneville Power Administration's obligation to serve electric load requirements of both publicly-owned and investor-owned utilities and BPA's direct service industrial customers of the Pacific Northwest region. The intention of the Act is to provide the Pacific Northwest with an adequate power supply, hold utility rates lower than they would be otherwise, and place maximum reliance on conservation and renewable energy resources while responding to growth in the demand for electric power.

Major Provisions of the Act are:

1. A Regional Planning Council will be formed with two representatives from each of the states of Washington, Oregon, Idaho, and Montana. The Council will draw up a plan for meeting the electric power needs of the region, taking into account the social and economic effects of alternative courses of action. The plan must give highest priority to cost-effective conservation as a resource preferable to all others. Following in order of priority are renewable resources and thermal generating plants, giving priority to fuel efficient methods of producing energy.

2. BPA is responsible for supplying the loads of customers and managing the regional electric power system to achieve the purpose of the Act relating to fish, system efficiency, and experimental projects. BPA may also purchase the generating capabilities of new thermal projects but only if it adheres to the Council's supply planning priority.

3. The supply preference and resulting price advantages to public utilities and co-ops are protected and enhanced by the new Act. In addition, BPA is now given the responsibility to supply the full future requirements of preferential customers.

4. The residential and farm customers of investor-owned utilities (IOU's) receive rate relief. The IOU's will sell to Bonneville, at the average cost of its power, an amount of electric energy equal to its residential and farm loads. Bonneville, in return, then sells to the IOU's enough energy at BPA standard rates to supply these residential and farm loads.

5. Direct service industries (DSI) receive new 20-year contracts for electric power from Bonneville, but at a higher price than they are paying under existing contracts. The DSI's, in effect, pay the cost of rate relief to the residential and farm customers of the IOU's during the first four years, and a substantial portion thereafter, in exchange for long-term contracts.

6. BPA sells electricity at a rate that reflects the melded cost of Federal hydropower with other more expensive resources.

7. The new regional council will establish a program to protect and enhance the fisheries' resources of the Columbia River. All planning must involve the public and must provide a method for balancing environmental protection and energy needs of the region.

The new Regional Planning Council members have been appointed by their respective governors and recently held an organizational meeting. The major task of the planning council is to adopt a Regional Electric Power and Conservation Plan within two years of the Council's formation and to update it periodically.

Bonneville Power Administration is very involved in the formidable task of implementing the new Act. The Pacific Northwest Utilities Conference Committee (PNUCC) will be working very closely with the Regional Planning Council in the near future. At present, the PNUCC has delayed issuing its annual "West Group Forecast" while studies are ongoing to expand the West Group Area boundaries to correspond with boundaries of the Regional Power Act. A comprehensive planning program and forecasting methodology must be developed for the new region.

Not included in the April 1981, ERA-411 report is the generating unit additions of the recently organized Deseret Generation and Transmission Cooperative. Deseret G&T, comprised of six R.E.A. Cooperatives, is a new member of the WSCC. Planned generating capacity additions consist of the Bonanza two-unit, coal-fired plant to be built in eastern Utah. Unit No. 1, 400 MW, is scheduled for completion in December 1984. Unit No. 2, 400 MW, is estimated to be in service in December 1988. Capacity of the Bonanza plant is not included in any of the tables. However, if the 800 MW of capacity is added to Tables 9B.13 and 9B.14, the actual reserves for the 1984 through 1987 winter peaks would increase by approximately one percent. For winter 1988 through 1990, the actual reserves would increase by about 1.7 percent.

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Table 9B.2

ACTUAL 1980 OPERATION BY TYPE OF PLANT

Northwest Power Pool Area

		Capability (as of 12-31-80)		Annual Energy		Fossil Fuel Consumption (x 1000)
Plant Type	Fuel Type	MW	% of Total	GWH	% of Total	
Hydro	Water	32209	74.7	130344	70.8	-
Hydro Pumped Storage	Water	100	0.2	0	0	-
Steam	Coal	8410	19.5	44176	24.0	26191 tons
Steam	Oil	316	0.7	114	0.1	261 bbls
Steam	Gas	-	-	583	0.3	7261 MCF
Steam	Nuclear	1080	2.5	8058	4.4	-
Combustion Turbine	Oil	403	0.9	4	-	5 bbls
Combustion Turbine	Gas	-	-	90	0.1	1060 MCF
Combined Cycle	Oil	530	1.2	58	-	88 bbls
Combined Cycle	Gas	-	-	31	-	323 MCF
Geothermal	GST	-	-	0	0	-
Internal Combustion	Oil	45	0.1	0	0	0
Cogeneration	- - -	4	-	610	0.3	-
Other		6	-	442	0.2	-
Total		43103	100.0	184103	100.0	

Total Fuel Consumption

Coal (tons x 1000)		26191
Gas (MCF x 1000)		8644
Gas (equivalent oil bbls x 1000)		1469
Oil: distillate (bbls x 1000)	93	
residual	261	
crude	0	
Total oil		354

Table 9B.3

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)

Northwest Power Pool Area 1/

	1979		Forecast 1980 4/		Actual 1980 3/	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	39169	40964	38611	39059	40543	38331
2. Peak Demand	23014	32788	26010	33888	23575	34092
3. Planned Reserves (1-2)	16155	8176	12601	5171	16968	4239
4. Planned Reserves (%) (3/2) x100	70.2	24.9	48.4	15.3	72.0	12.4
5. Net Transactions (Imports - Exports)	-3013	-1767	-2956	-1605	-2975	-1549
6. Total Capability (1+5)	36156	39197	35655	37454	37568	36782
7. Total Reserves (6-2)	13142	6409	9645	3566	13993	2690
8. Total Reserves (%) (7/2) x100	57.1	19.5	37.1	10.5	59.4	7.9
9. Scheduled Maintenance	7398	3741	2633	781	5056	969
10. Capability After Maintenace (6-9)	28758	35456	33022	36673	32512	35813
11. Reserves After Maintenance (10-2)	5744	2668	7012	2785	8937	1721
12. Reserves After Maintenance (%) (11/2) x100	25.0	8.1	27.0	8.2	37.9	5.0
13. Full Forced Outage 2/	0	323	0	0	2700	0
14. Capability After Forced Outage (10-13)	28758	35133	33022	36673	29812	35813
15. Reserves After Forced Outage (14-2)	5745	2345	7012	2785	6237	1721
16. Reserves After Forced Outage (%) (15/2) x100	25.0	7.2	27.0	8.2	26.5	26.5
17. Other Unavailable Capability	30	169	167	167	136	155
18. Actual Capability (14-17)	28728	34964	32855	36506	29676	35658
19. Actual Reserves (18-2)	5714	2176	6845	2618	6101	1566
20. Actual Reserves (%) (19/2) x100	24.8	6.6	26.3	7.7	25.9	4.6

1/ Excludes Canadian Systems.
2/ Information not reported separately.
3/ Winter 1980-81 estimated for January 1981 in the 1981 ERA-411 Report.
4/ Forecast as reported in WSCC, ERA-411 Report, April 1980.

Table 9B.4

ESTIMATED 1981 OPERATION BY TYPE OF PLANT

Northwest Power Pool Area

Plant Type	Fuel Type	Capability (as of January 1982) MW	Capability (as of January 1982) % of Total	Annual Energy GWH	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	27866	70.5	138552	70.7	-
Hydro Pumped Storage	Water	300	0.8	0	0	-
Steam	Coal	8585	21.7	43940	224	25767 tons
Steam	Oil	316	0.8	89	-	190 bbls
Steam	Gas	-	-	253	0.1	3358 MCF
Steam	Nuclear	1080	2.7	11200	5.7	-
Combustion Turbine	Oil	761	1.9	205	0.1	438 bbls
Combustion Turbine	Gas	-	-	87	-	1070 MCF
Combined Cycle	Oil	534	1.4	0	0	0
Combined Cycle	Gas	-	-	1318	0.7	17531 MCF
Geothermal	GST	0	0	0	0	0
Internal Combustion	Oil	45	0.1	0	0	0
Cogeneration	- - -	28	0.1	254	0.1	-
Other		6	-	12	-	-
Total		39521	100.0	195910	100.0	

Total Fuel Consumption

Coal (tons x 1000)		25767
Gas (MCF x 1000)		21959
Gas (equivalent oil bbls x 1000)		3733
Oil: distillate (bbls x 1000)	438	
residual	190	
crude	0	
Total oil		628

Table 9B.5

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
NORTHWEST POWER POOL AREA (REGION 25)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	39222	39408
2. PEAK DEMAND	26890	34530
3. PLANNED RESERVES (1-2)	12332	4878
4. PLANNED RESERVES (%) (3/2)X100	45.9	14.1
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-3257	-1030
6. TOTAL CAPABILITY (1+5)	35965	38378
7. TOTAL RESERVES (6-2)	9075	3848
8. TOTAL RESERVES (%) (7/2)X100	33.7	11.1
9. SCHEDULED MAINTENANCE 1/	3745	2286
10. CAPABILITY AFTER MAINTENANCE (6-9)	32220	36092
11. RESERVES AFTER MAINTENANCE (10-2)	5330	1562
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	19.8	4.5
13. FULL FORCED OUTAGES 1/	981	1261
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	31239	34831
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	4349	301
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	16.2	0.9
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1098	315
18. ACTUAL CAPABILITY (14-17)	30141	34516
19. ACTUAL RESERVES (18-2)	3251	-14
20. ACTUAL RESERVES (%) (19/2)X100	12.1	-0.0

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

[redacted]

Table 9B.6

PROJECTED ENERGY AND DEMAND GROWTH RATES
Northwest Power Pool Area

	Energy Requirements		Summer Peak Demand		Winter Peak Demand		Annual Load Factor
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	(%)
1981	194540	12.5	26890	14.1	34530	1.3	64.3
1982	200369	3.0	27290	1.5	36176	4.8	63.2
1983	209093	4.4	28413	4.1	37780	4.4	63.2
1984	219732	5.1	29739	4.7	39350	4.2	63.7
1985	226648	3.1	30682	3.2	40672	3.4	63.6
% Growth 1981-1985		3.9		3.4		4.2	
1986	235960	4.1	31694	3.3	42052	3.4	64.1
1987	243677	3.3	32704	3.2	43481	3.4	64.0
1988	252759	3.7	33765	3.2	45020	3.5	64.1
1989	260812	3.2	34905	3.4	46603	3.5	63.9
1990	269528	3.3	36061	3.3	46639	0.1	66.0
% Growth 1986-1990		3.4		3.3		2.6	
% Growth 1981-1990		3.7		3.3		3.4	

Table 9B.7

SUMMARY OF GENERATION ADDITIONS AND CHANGES

Northwest Power Pool Area

(Winter Capability - MW)

Generation Type	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	10-Yr. Period	% of Total
Hydro-Conventional	334	381		360	280	448	303	276	622		3004	19.8
Hydro-Pumped Storage	150	50									200	1.3
Steam-Coal			400	700	1100	316	816	816	1146		5294	34.9
Steam-Gas and Oil												
Nuclear			1100			2490	2490				6080	40.1
Combustion Turbine	356		42				150	25			573	3.7
Combined Cycle												
Internal Combustion												
Geothermal				20							20	0.1
Other												
Total	840	431	1542	1080	1380	3254	3759	1117	1768	0	15171	100.0

[redacted]

Table 9B.8

PLANNED SIGNIFICANT ADDITIONS TO GENERATING CAPACITY

Northwest Power Pool Area

Unit Name & Number	Type	Capability (MW)	Scheduled In-service Date	Delay Since 1/ Last Year (Months)
Whitehorn 2 & 3	Comb. Turb.	178	5/81	6
Frederickson 1 & 2	Comb. Turb.	178	11/81	-
Hunter 3	Coal	400	6/83	-
WNP 2	Nuclear	1100	9/83	8
Colstrip 3	Coal	700	1/84	-
Hunter 4	Coal	400	6/85	-
Colstrip 4	Coal	700	7/85	-
Ross 1 - 4	Hydro	+244	12/85	-
WNP 1	Nuclear	1250	2/86	8
Intermountain 1	Coal	750 2/	7/86	-
WNP 3	Nuclear	1240	9/86	3
Wyodak 2	Coal	310	12/86	-
WNP 4	Nuclear	1250	2/87	8
Dworshak 4	Hydro	253	4/87	-
Creston 1	Coal	500	7/87	-
Intermountain 2	Coal	750 2/	7/87	-
WNP 5	Nuclear	1240	9/87	-
MPC	Comb. Turb.	150	11/87	-
Wellington 1	Coal	500	6/88	-
Intermountain 3	Coal	750 2/	7/88	-
Creston 2	Coal	500	1/89	-
MPC Thermal	Coal	330	7/89	-
Intermountain 4	Coal	750 2/	7/89	-
Skagit 1	Nuclear	1285	1/91	6
Pebble Springs 1	Nuclear	1260	Indef. 3/	25+

1/ Number of months, if any, that the unit has been delayed from the schedule in the 1980 Electric Power Supply and Demand Report.

2/ Intermountain project: owner/operator, Los Angeles Dept. of Water and Power; participation, 316 MW shared by Utah utilities, 434 MW by Southern California utilities.

3/ Delayed beyond the study period.

Table 9B.9

ESTIMATED 1985 OPERATION BY TYPE OF PLANT

Northwest Power Pool Area

Plant Type	Fuel Type	Capability (as of January 1985)		Annual Energy		Fossil Fuel Consumption (x 1000)
		MW	% of Total	GWH	% of Total	
Hydro	Water	30185	66.7	141132	63.0	-
Hydro Pumped Storage	Water	300	0.7	0	0	-
Steam	Coal	10824	23.9	65050	29.0	37412 Tons
Steam	Oil	316	0.7	219	0.1	466 bbls
Steam	Gas	-	-	263	0.1	3490 MCF
Steam	Nuclear	2180	4.8	13254	5.9	-
Combustion Turbine	Oil	761	1.7	315	0.1	674 bbls
Combustine Turbine	Gas	-	-	176	0.1	2196 MCF
Combined Cycle	Oil	534	1.2	0	0	0
Combined Cycle	Gas	-	-	2637	1.2	35072 MCF
Geothermal	GST	20	-	150	0.1	-
Internal Combustion	Oil	45	0.1	0	0	0
Cogeneration	- -	28	0.1	508	0.2	-
Other	- -	48	0.1	307	0.1	-
Total		45241	100.0	224011	100.0	

Total Fuel Consumption

Coal (tons x 1000)		37412
Gas (MCF x 1000)		40758
Gas (equivalent oil bbls x 1000)		6928
Oil: distillate (bbls x 1000)	674	
residual	466	
crude	0	
Total oil		1140

Table 9B.10

ESTIMATED 1990 OPERATION BY TYPE OF PLANT

Northwest Power Pool Area

Plant Type	Fuel Type	Capability (as of December 1990) MW	Capability (as of December 1990) % of Total	Annual Energy GWH	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	31259	57.0	142294	52.6	-
Hydro Pumped Storage	Water	300	0.6	0	0	-
Steam	Coal	14237	26.0	81524	30.2	45874 tons
Steam	Oil	316	0.6	50	-	106 bbls
Steam	Gas	-	-	180	0.1	2389 MCF
Steam	Nuclear	7160	13.1	43993	16.3	-
Combustion Turbine	Oil	935	1.7	100	-	214 bbls
Combustine Turbine	Gas	-	-	80	-	998 MCF
Combined Cycle	Oil	530	1.0	0	0	0
Combined Cycle	Gas	-	-	1200	0.4	15960 MCF
Geothermal	GST	20	-	150	0.1	-
Internal Combustion	Oil	45	0.1	0	0	0
Cogeneration	- -	4	-	508	0.2	-
Other	- -	48	0.1	307	0.1	-
Total		54854	100.0	270386	100.0	

Total Fuel Consumption

Coal (tons x 1000)		45874
Gas (MCF x 1000)		19347
Gas (equivalent oil bbls x 1000)		3288
Oil: distillate (bbls x 1000)	214	
residual	106	
crude	0	
Total oil		320

Table 9B.11

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Northwest Power Pool Area

Summer Capability

			Oil and Gas						Hydro 2/		
	Nuclear Steam	Coal Steam	Steam	Combined Cycle	Combust. Turbine	Geo-Thermal	Cogen-eration	Other 1/	Conven-tional	Pumped Storage	Total Capability
1981	1080	8460	190	500	557	0	28	51	28334	0	39210
% Total	2.8	21.6	0.5	1.3	1.4	0	0.1	0.1	72.3	0	
1982	1080	8685	316	500	735	0	28	51	28737	0	40132
% Total	2.7	21.6	0.8	1.3	1.8	0	0.1	0.1	71.6	0	
1983	1080	8935	316	500	735	0	28	51	28860	0	40505
% Total	2.7	22.1	0.8	1.2	1.8	0	0.1	0.1	71.3	0	
1984	2180	9586	442	500	735	20	28	93	30737	0	44321
% Total	4.9	21.6	1.0	1.1	1.7	0.1	0.1	0.2	69.4	0	
1985	2180	10173	316	500	735	20	28	93	30830	0	44875
% Total	4.9	22.7	0.7	1.1	1.6	0.0	0.1	0.2	68.7	0	
1986	3430	10887	316	500	735	20	28	93	30684	0	46693
% Total	7.4	23.3	0.7	1.1	1.6	0.0	0.1	0.2	65.7	0	
1987	5920	11451	316	500	735	20	28	93	31223	0	50286
% Total	11.8	22.8	0.6	1.0	1.5	0.0	0.1	0.2	62.1	0	
1988	7160	12766	316	500	885	20	28	93	31242	0	53010
% Total	13.5	24.1	0.6	0.9	1.7	0.0	0.1	0.2	58.9	0	
1989	7160	13587	316	500	910	20	28	93	31230	0	53844
% Total	13.3	25.2	0.6	0.9	1.7	0.0	0.1	0.2	58.0	0	
1990	7160	14237	316	500	910	20	28	93	31260	0	54524
% Total	13.1	26.1	0.6	0.9	1.7	0.0	0.1	0.2	57.3	0	

1/ Other capability includes wind and oil-fired diesel generation (45 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

Table 9B.12

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Northwest Power Pool Area

Winter Capability

			Oil and Gas						Hydro 2/		
	Nuclear Steam	Coal Steam	Steam	Combined Cycle	Combust. Turbine	Geo-Thermal	Cogen-eration	Other 1/	Conven-tional	Pumped Storage	Total Capability
1981	1080	8585	316	534	761	0	28	51	27866	300	39521
% Total	2.7	21.7	0.8	1.4	1.9	0	0.1	0.1	70.5	0.8	
1982	1080	8685	316	534	761	0	28	51	28234	300	39989
% Total	2.7	21.7	0.8	1.3	1.9	0	0.1	0.1	70.6	0.8	
1983	2180	9586	442	534	761	0	28	93	29882	300	43806
% Total	5.0	21.9	1.0	1.2	1.7	0	0.1	0.2	68.2	0.7	
1984	2180	9711	316	534	761	20	28	93	29814	300	43757
% Total	5.0	22.2	0.7	1.2	1.7	0.1	0.1	0.2	68.1	0.7	
1985	2180	10824	316	534	761	20	28	93	30185	500	45241
% Total	4.8	23.9	0.7	1.2	1.7	0.0	0.1	0.2	66.7	0.7	
1986	4670	11451	316	534	761	20	28	93	30522	300	48695
% Total	9.6	23.5	0.7	1.1	1.6	0.0	0.1	0.2	62.7	0.6	
1987	7160	12266	316	534	911	20	28	93	30656	300	52284
% Total	13.7	23.5	0.6	1.0	1.7	0.0	0.1	0.2	58.6	0.6	
1988	7160	13582	316	534	936	20	28	93	30621	300	53590
% Total	13.4	25.3	0.6	1.0	1.8	0.0	0.1	0.2	57.1	0.6	
1989	7160	14232	316	534	936	20	28	93	30752	300	54371
% Total	13.2	26.2	0.6	1.0	1.7	0.0	0.1	0.2	56.6	0.6	
1990	7160	14237	316	534	936	20	28	93	31259	300	54883
% Total	13.1	25.9	0.6	1.0	1.7	0.0	0.1	0.2	57.0	0.6	

1/ Other capability includes wind and oil-fired diesel generation (45 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

Table 9B.13

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1982-1985
NORTHWEST POWER POOL AREA (REGION 25)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	39919	35776	40442	43792	44307	43618	44674	45089
2. PEAK DEMAND	27290	32176	28413	37780	29739	39350	30682	40672
3. PLANNED RESERVES (1-2)	12629	3600	12029	6012	14568	4268	13992	4417
4. PLANNED RESERVES (%) (3/2)X100	46.3	11.2	42.3	15.9	49.0	10.8	45.6	10.9
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-2301	-933	-2304	-1001	-2432	-940	-2249	-951
6. TOTAL CAPABILITY (1+5)	37618	34843	38138	42791	41875	42678	42425	44138
7. TOTAL RESERVES (6-2)	10328	2667	9725	5011	12136	3328	11743	3466
8. TOTAL RESERVES (%) (7/2)X100	37.8	7.4	34.2	13.3	40.8	8.5	38.3	8.5
9. SCHEDULED MAINTENANCE 1/	5269	2307	5338	2540	5849	2530	5897	2615
10. CAPABILITY AFTER MAINTENANCE (6-9)	32349	32536	32800	40251	36026	40148	36528	41523
11. RESERVES AFTER MAINTENANCE (10-2)	5059	360	4387	2471	6287	798	5846	851
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	18.5	1.0	15.4	6.5	21.1	2.0	19.1	2.1
13. FULL FORCED OUTAGES 1/	998	1273	1011	1301	1108	1396	1117	1443
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	31351	35263	31789	38950	34918	38752	35411	40080
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	4061	-913	3375	1170	5179	-598	4729	-592
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	14.9	-2.5	11.9	2.8	17.4	-1.5	15.4	-1.5
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1118	318	1132	350	1241	349	1251	361
18. ACTUAL CAPABILITY (14-17)	30233	34945	30657	38500	33677	38403	34160	39719
19. ACTUAL RESERVES (18-2)	2943	-1231	2244	720	3938	-947	3478	-953
20. ACTUAL RESERVES (%) (19/2)X100	10.8	-3.4	7.9	1.9	13.2	-2.4	11.3	-2.3

POSSIBLE NUCLEAR UNIT DELAYS ESTIMATED BY DOE

21. POSSIBLE NUCLEAR DELAYS	0	0	0	1100	1100	0	0	0
22. ACTUAL CAPABILITY WITH NUCLEAR DELAYS (18-21)	30233	34945	30657	37400	32577	38403	34160	39719
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (22-1)	2943	-1231	2244	-380	2838	-947	3478	-953
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2)X100	10.8	-3.4	7.9	-1.0	9.5	-2.4	11.3	-2.3

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

25. POSSIBLE COAL DELAYS	0	0	400	651	0	125	463	63
26. ACTUAL CAPABILITY W/NUCLEAR & COAL DELAYS (22-25)	30233	34945	30257	36749	32577	38278	33697	39656
27. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (26-2)	2943	-1231	1844	-1031	2838	-1072	3015	-1016
28. ACTUAL RESERVES (%) W/NUCLEAR & COAL DELAYS	10.8	-3.4	6.5	-2.7	9.5	-2.7	9.8	-2.5

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Table 9B.14

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1986-1990
NORTHWEST POWER POOL AREA (REGION 25)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	46478	48226	49817	51500	52226	52490	52739	52951	53199	53429
2. PEAK DEMAND	31694	42052	32704	43481	33765	45020	34905	46603	36061	46639
3. PLANNED RESERVES (1-2)	14784	6174	17113	8019	18461	7470	17834	6348	17139	6790
4. PLANNED RESERVES (%) (3/2)X100	46.6	14.7	52.3	18.4	54.7	16.6	51.1	13.6	47.5	14.6
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-2259	-60	-789	875	54	1250	484	1566	760	1505
6. TOTAL CAPABILITY (1+5)	44219	48166	49028	52375	52280	53740	53223	54517	53959	54934
7. TOTAL RESERVES (6-2)	12525	6114	16324	8894	18515	8720	18318	7914	17898	8295
8. TOTAL RESERVES (%) (7/2)X100	39.5	14.5	49.9	20.5	54.8	19.4	52.5	17.0	49.6	17.8
9. SCHEDULED MAINTENANCE 1/	6135	2797	6576	2987	6894	3044	6962	3071	7009	3099
10. CAPABILITY AFTER MAINTENANCE (6-9)	38084	45369	42452	49388	45386	50696	46261	51446	46950	51835
11. RESERVES AFTER MAINTENANCE (10-2)	6390	3317	9748	5907	11621	5676	11356	4843	10889	5196
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	20.2	7.9	29.8	13.6	34.4	12.6	32.5	10.4	30.2	11.1
13. FULL FORCED OUTAGES 1/	1162	1543	1245	1648	1306	1680	1318	1694	1327	1710
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	36922	43826	41207	47740	44080	49016	44943	49752	45623	50125
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	5228	1774	8503	4259	10315	3996	10038	3149	9562	3486
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	16.5	4.2	26.0	9.8	30.5	8.9	28.8	6.8	26.5	7.5
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1301	386	1395	412	1462	420	1477	424	1487	427
18. ACTUAL CAPABILITY (14-17)	35621	43440	39812	47328	42618	48596	43466	49328	44136	49698
19. ACTUAL RESERVES (18-2)	3927	1388	7108	3847	8853	3576	8561	2725	8075	3059
20. ACTUAL RESERVES (%) (19/2)X100	12.4	3.3	21.7	8.8	26.2	7.9	24.5	5.8	22.4	6.6

POSSIBLE NUCLEAR UNIT DELAYS ESTIMATED BY DOE

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. POSSIBLE NUCLEAR DELAYS	1250	2490	2490	2490	1240	0	0	0	0	0
22. ACTUAL CAPABILITY WITH NUCLEAR DELAYS (18-21)	34371	40950	37322	44838	41378	48596	43466	49328	44136	49698
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (22-2)	2677	-1102	4618	1357	7613	3576	8561	2725	8075	3059
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2)X100	8.4	-2.6	14.1	3.1	22.5	7.9	24.5	5.8	22.4	6.6

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
25. POSSIBLE COAL DELAYS	126	374	126	126	126	126	126	626	126	126
26. ACTUAL CAPABILITY W/NUCLEAR & COAL DELAYS (22-25)	34245	40576	37196	44712	41252	48470	43340	48702	44010	49572
27. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (26-2)	2551	-1476	4492	1231	7487	3450	8435	2099	7949	2933
28. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (%)	8.0	-3.5	13.7	2.8	22.2	7.7	24.2	4.5	22.0	6.3

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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C. Arizona - New Mexico Power Area

Electric Region 26

Arizona - New Mexico Power Area (AZ - MW) encompasses Arizona, most of New Mexico, and small portions of southeast Calfiornia and western Texas. The region is comprised of 13 members and 2 affiliate members of the WSCC plus 28 other organizations. A complete listing of members and others serving the region is in Appendix B.

Historical Perspective

The region historically is noted for its high growth rates of energy use and peak demand. Growth rates of over 7 percent were prevalent during the 1960's and early 1970's. Although in recent years annual growth has decreased somewhat, energy and peak demand growth remains substantial.

The summer peak demand for 1980 increased 6.2 percent over 1979, while annual energy use increased by 4.8 percent. In comparison, the average annual growth rates for the period 1977-1980 were 5.1 percent for peak demand and 5.2 percent for energy. Actual loads for 1980 are shown in Table 9C.1.

Table 9C.1

1980 Load Growth

Arizona - New Mexico Power Area

	1980
Energy Load (Gwh)	41630
Growth Rate from 1979 (%)	4.8
Peak Demand (MW)	8436
Growth Rate from 1979 (%)	6.2
Load Factor (%)	56.3

Major additions to the region's generating capability during 1980 were two coal-fired units: Cholla Unit No. 3 (245 MW), and Coronado Unit No. 2 (350 MW). In 1980, coal-fired generating plants supplied 68.6 percent of the regions's total electric generation, followed by oil/gas-fired generation at 23.8 percent. Consumption of natural gas in 1980 amounted to 96.6 million MCF -- equivalent to 16.4 million barrels of oil. Oil consumption was 2.4 million barrels. Actual and equivalent oil use in 1980 decreased by 22.4 percent from 1979. Table 9C.2 shows actual operation by type of plant and fuel use for 1980.

Generating capability and reserves for the summer and winter peak months of 1980 are shown in Table 9C.3. For comparison, the previous forecast as presented in the 1980 issuance of this report is included. The actual 1980 summer peak was 3.7 percent under forecast.

Current Perspective

The 1981 forecast for the Arizona - New Mexico Power Area estimates that electric energy consumption will increase by 3,466 Gwh or 8.3 percent over 1980. The only major additions to the region's generating capability in 1981 is the coal-fired, Cholla Unit No. 4 (347 MW) scheduled for service in June. Early in 1981, 2 units (26 MW) of oil-fired generation were retired and 3 units (33 MW) of natural gas-fired generation were placed in deactivated status.

Estimated 1981 operation by type of plant and fuel consumption for the Arizona - New Mexico Power Area is shown in Table 9C.4.

Projected peak loads and reserve margins for 1981 summer and winter seasons are shown in Table 9C.5. A discussion of the 1981 summer supply and demand forecast, previously published, is included in Appendix C.

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Future Perspective

The combined Arizona - New Mexico Power Area's summer peak load is projected to increase at an average annual rate of 5.7 percent from 1981 to 1985. Energy consumption is estimated to increase at an average annual rate of 6.4 percent during the same period.

The 1981 ERA-411 report shows a reduction in the load forecast compared to the previous report of 1980. Estimated energy consumption for 1985 has been reduced by 3,216 Gwh (5.3%) to 57,738 Gwh. Also, estimated peak demand for 1985 was reduced by 696 MW (5.3%) to 11,191 MW.

During the 1986-1990 period, the annual growth rates for peak demand and energy are projected to decrease to 4.3 percent and 4.6 percent, respectively. Projected energy use and peak demand growth rates are listed for the 10-year period 1981-1990 in Table 9C.6.

Planned additions to the region's generating capability total 3,969 MW during the period 1981-85. Included are 1,341 MW of coal-fired capability and 2,540 MW of nuclear generating capability from the Palo Verde plant. Construction of the Palo Verde Unit No. 1 (1270 MW) is over 75 percent complete and is expected to be in service for the summer of 1983. Table 9C.7 summarizes the capacity additions by fuel type for the period 1981 to 1990. Of the total capability planned for installation during the 10-year period, 91.5 percent is from coal and nuclear units.

Table 9C.8 lists the major capacity additions by unit for the period 1981-90. Changes in scheduling since the previous DOE "Electric Power Supply and Demand Report of July 1980" are indicated in the 'Months Delay' column. Coronado Unit No. 3, previously scheduled for June 1989, had been delayed indefinitely due to reduced load forecasts. According to recent information, Cholla Unit No. 5, delayed 2 years in this report, may be delayed an additional 3 years.

Tables 9C.9 and 9C.10 show the estimated generation by type of plant and fuel consumption for 1985 and 1990. In 1990, it is projected that only about 5.8 percent of the total generation will come from oil/gas-fired plants. This is a considerable reduction from the 23.9 percent of total generation supplied by oil/gas-fired units in 1980.

In Tables 9C.11 and 9C.12, planned net capability by type of plant is shown for the summer and winter seasonal peaks for 1981 through 1990.

Tables 9C.13 and 9C.14 show reserve margin projections for the summer and winter peak periods for the years 1982 through 1990. For this report, estimates of generating unit maintenance and forced outages, based on historical data, are included to assess the effect of possible outages on reserve margins. If these outages, estimated loads and capacity additions do occur, actual reserves are projected to remain adequate. However, further delays in construction of major generating units could have an adverse effect on the region's reserve margins. Staff assumed delays of six months for coal-fired units and one year for nuclear units to study this effect. Considering possible outages plus additional unit delays, Tables 9C.13 and 9C.14 show actual reserve margins could drop to 9.6 percent in 1984. However, this amount should still provide an adequate level of reliability.

Completion of Public Service Company of New Mexico's Ojo - Norton and Norton to B-A 345 KV transmission line has been delayed due to processing by the Bureau of Land Management. Efforts are being made to separate the project into two components. If successful, the Norton to B-A station segment (41 miles) should be completed in late 1982. The remaining Ojo - Norton segment (26 miles) should be completed in 1985. This delay will stress the existing northern New Mexico transmission system and may result in marginal or unacceptable system performance under certain conditions.

Table 9C.2

ACTUAL 1980 OPERATION BY TYPE OF PLANT

Arizona - New Mexico Power Area

Plant Type	Fuel Type	Capability (as of 12-31-80) MW	Capability (as of 12-31-80) % of Total	Annual Energy GWH	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	646	5.6	3410	7.3	-
Hydro Pumped Storage	Water	137	1.2	113	0.2	-
Steam	Coal	5648	48.7	32043	68.6	17316 tons
Steam	Oil	2854	24.6	1141	2.4	2126 bbls
Steam	Gas	-	-	7804	16.7	76160 MCF
Steam	Nuclear	0	0	0	0	-
Combustion Turbine	Oil	1485	12.8	110	0.2	82 bbls
Combustion Turbine	Gas	-	-	834	1.8	8400 MCF
Combined Cycle	Oil	805	7.0	88	0.2	160 bbls
Combined Cycle	Gas	-	-	1165	2.5	12042 MCF
Geothermal	GST	0	0	0	0	0
Internal Combustion	Oil	15	0.1	0	0	0
Cogeneration		0	0	0	0	-
Other		0	0	0	0	-
Total		11590	100.0	46708	100.0	

Total Fuel Consumption

Coal (tons x 1000)		17316
Gas (MCF x 1000)		96602
Gas (equivalent oil bbls x 1000)		16422
Oil: distillate (bbls x 1000)	420	
residual	1948	
crude	0	
Total oil		2368

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Table 9C.3

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Arizona - New Mexico Power Area

	Forecast 1980		Actual 1980	
	Summer	Winter	Summer	Winter 1/
1. Planned Capability	11088	11542	11339	11486
2. Peak Demand	8757	6475	8436	6215
3. Planned Reserves (1-2)	2331	5067	2903	5271
4. Planned Reserves (%) (3/2) x100	26.6	78.3	34.4	84.8
5. Net Transactions (Imports - Exports)	35	53	-100	-97
6. Total Capability (1+5)	11123	11595	11239	11389
7. Total Reserves (6-2)	2366	5120	2803	5174
8. Total Reserves (%) (7/2) x100	27.0	79.1	33.2	83.3
9. Scheduled Maintenance	0	1573	0	1654
10. Capability After Maintenace (6-9)	11123	10022	11239	9735
11. Reserves After Maintenance (10-2)	2366	3547	2803	3520
12. Reserves After Maintenance (%) (11/2) x100	27.0	54.8	33.2	56.6
13. Full Forced Outage	430	660	48	0
14. Capability After Forced Outage (10-13)	10693	9362	11191	9735
15. Reserves After Forced Outage (14-2)	1936	2887	2755	3520
16. Reserves After Forced Outage (%) (15/2) x100	22.1	44.6	32.7	56.6
17. Other Unavailable Capability	11	27	87	48
18. Actual Capability (14-17)	10682	9335	11104	9687
19. Actual Reserves (18-2)	1925	2860	2668	3472
20. Actual Reserves (%) (19/2) x100	22.0	44.2	31.6	55.9

1/ Estimated for January 1981

Table 9C.4

ESTIMATED 1981 OPERATION BY TYPE OF PLANT

Arizona - New Mexico Power Area

Plant Type	Fuel Type	Capability (as of July 1981)		Annual Energy		Fossil Fuel Consumption (x 1000)
		MW	% of Total	GWH	% of Total	
Hydro	Water	649	5.5	2195	4.8	-
Hydro Pumped Storage	Water	137	1.2	276	0.6	-
Steam	Coal	5945	50.6	33706	73.5	18827 tons
Steam	Oil	2768	23.6	2291	5.0	3998 bbls
Steam	Gas	-	-	5503	12.0	59118 MCF
Steam	Nuclear	0	0	0	0	-
Combustion Turbine	Oil	1444	12.3	57	0.1	136 bbls
Combustion Turbine	Gas	-	-	298	0.7	3839 MCF
Combined Cycle	Oil	795	6.8	256	0.6	447 bbls
Combined Cycle	Gas	-	-	1251	2.7	12166 MCF
Geothermal	GST	0	0	0	0	0
Internal Combustion	Oil	15	0.1	1	-	3 bbls
Cogeneration	- -	0	0	0	0	0
Other	- -	0	0	15	-	-
Total		11753	100.0	45849	100.0	

Total Fuel Consumption

Coal (tons x 1000)			18827
Gas (MCF x 1000)			75123
Gas (equivalent oil bbls x 1000)			12770
Oil:	distillate (bbls x 1000)	982	
	residual	3602	
	crude	0	
	Total oil		4584

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Table 9C.5

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
ARIZONA-NEW MEXICO AREA (REGION 26)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	13404	13538
2. PEAK DEMAND	8960	6560
3. PLANNED RESERVES (1-2)	4444	6978
4. PLANNED RESERVES (%) (3/2)X100	49.6	106.4
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-1542	-1632
6. TOTAL CAPABILITY (1+5)	11862	11906
7. TOTAL RESERVES (6-2)	2902	5346
8. TOTAL RESERVES (%) (7/2)X100	32.4	81.5
9. SCHEDULED MAINTENANCE 1/	0	1801
10. CAPABILITY AFTER MAINTENANCE (6-9)	11862	10105
11. RESERVES AFTER MAINTENANCE (10-2)	2902	3545
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	32.4	54.0
13. FULL FORCED OUTAGES 1/	550	406
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	11312	9699
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2352	3139
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	26.2	47.9
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	241	366
18. ACTUAL CAPABILITY (14-17)	11071	9333
19. ACTUAL RESERVES (18-2)	2111	2773
20. ACTUAL RESERVES (%) (19/2)X100	23.6	42.3

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

[redacted]

Table 9C.6

PROJECTED ENERGY AND DEMAND GROWTH RATES

Arizona - New Mexico Power Area

	Energy Requirements (GWH)	Energy Requirements Growth (%)	Summer Peak Demand (MW)	Summer Peak Demand Growth (%)	Winter Peak Demand (MW)	Winter Peak Demand Growth (%)	Annual Load Factor (%)
1981	45096	8.3	8960	6.2	6560	5.6	57.5
1982	48592	7.8	9509	6.1	6873	4.8	58.3
1983	50687	4.3	9930	4.4	7193	4.7	58.3
1984	53259	5.1	10409	4.8	7694	7.0	58.4
1985	57738	8.4	11191	7.5	8287	7.7	58.9
% Growth 1981-1985		6.4		5.7		6.0	
1986	61346	6.2	11817	5.6	8679	4.7	59.3
1987	64316	4.8	12346	4.5	9052	4.3	59.5
1988	67617	5.1	12911	4.6	9426	4.1	59.8
1989	70442	5.7	13454	4.2	9828	4.3	59.8
1990	73352	4.1	13998	4.0	10218	4.0	59.8
% Growth 1986-1990		4.6		4.3		4.2	
% Growth 1981-1990		5.6		5.1		5.0	

Table 9C.7

SUMMARY OF GENERATION ADDITIONS AND CHANGES

Arizona - New Mexico Power Area

(Winter Capability - MW)

Generation Type	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	10-Yr. Period	% of Total
Hydro-Conventional	1										1	.0%
Hydro-Pumped Storage										300	300	3.6%
Steam-Coal	347	449	-15	210	350		690	570		1200	3801	45.7%
Steam-Gas and Oil	-59								-63	-123	-245	-2.9%
Nuclear			1270	1270		1270					3810	45.8%
Combustion Turbine			50		-2						48	.6%
Combined Cycle										-2	-2	-.0%
Geothermal		48	50			50		50		50	248	3.0%
Internal Combustion												.0%
Cogeneration												.0%
Other										350	350	4.2%
Total	289	497	1355	1480	348	1320	690	620	-63	1775	8311	100.0%

[redacted]

Table 9C.8

PLANNED SIGNIFICANT ADDITIONS TO GENERATING CAPACITY

Arizona - New Mexico Power Area

Unit Name & Number	Type	Capability (MW)	Scheduled In-service Date	Delay Since Last Year (Months)[1]
San Juan 4	Coal	472	5/82	
Palo Verde 1	Nuclear	1270	5/83	
Palo Verde 2	Nuclear	1270	5/84	
Escalante 1	Coal	210	6/84	
Springerville 1	Coal	350	6/85	
Palo Verde 3	Nuclear	1270	5/86	
Cholla 5	Coal	340	6/87	24
Springerville 2	Coal	350	6/87	
Escalante 2	Coal	210	6/88	
AEPCO 1	Coal	360	6/88	
New Mexico Station	Coal	490	5/90	
Pumped Storage	Hydro	300	5/90	12
AEPCO 2	Coal	360	6/90	
APS	UNK	350	6/90	
Springerville 3	Coal	350	6/90	
Coronado 3	Coal	350	Indef.[2]	18 +

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[1] Number of months, if any, that the unit has been delayed from the schedule in the 1980 Electric Power Supply and Demand report.

[2] Delayed beyond the study period.

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Table 9C.9

ESTIMATED 1985 OPERATION BY TYPE OF PLANT

Arizona - New Mexico Power Area

Plant Type	Fuel Type	Capability (as of July 1985) MW	Capability (as of July 1985) % of Total	Annual Energy GWH	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	649	4.3	2255	3.8	-
Hydro Pumped Storage	Water	137	0.9	271	0.5	-
Steam	Coal	7025	46.5	37548	63.1	20575 tons
Steam	Oil	2768	18.3	2809	4.7	4900 bbls
Steam	Gas	-	-	3267	5.5	35324 MCF
Steam	Nuclear	1994	13.2	10840	18.2	-
Combustion Turbine	Oil	1640	10.8	123	0.2	307 bbls
Combustion Turbine	Gas	-	-	225	0.4	3075 MCF
Combined Cycle	Oil	795	5.3	284	0.5	488 bbls
Combined Cycle	Gas	-	-	1275	2.1	12522 MCF
Geothermal	GST	98	0.6	578	1.0	-
Internal Combustion	Oil	15	0.1	3	-	8 bbls
Cogeneration	- -	0	0	0	0	-
Other		0	0	0	0	-
Total		15121	100.0	59478	100.0	

Total Fuel Consumption

Coal (tons x 1000)			20575
Gas (MCF x 1000)			50921
Gas (equivalent oil bbls x 1000)			8656
Oil:	distillate (bbls x 1000)	504	
	residual	5199	
	crude	0	
	Total oil		5703

Table 9C.10

ESTIMATED 1990 OPERATION BY TYPE OF PLANT

Arizona - New Mexico Power Area

Plant Type	Fuel Type	Capability (as of July 1990)		Annual Energy		Fossil Fuel Consumption (x 1000)
		MW	% of Total	GWH	% of Total	
Hydro	Water	649	3.5	2248	3.1	-
Hydro Pumped Storage	Water	287	1.5	458	0.6	-
Steam	Coal	9294	49.7	46631	64.4	24552 tons
Steam	Oil	2582	13.8	2096	2.9	3722 bbls
Steam	Gas	-	-	1207	1.7	13241 MCF
Steam	Nuclear	2991	16.0	17748	24.5	-
Combustion Turbine	Oil	1492	8.0	54	0.1	136 bbls
Combustion Turbine	Gas	-	-	60	0.1	780 MCF
Combined Cycle	Oil	793	4.2	657	0.9	1109 bbls
Combined Cycle	Gas	-	-	94	0.1	973 MCF
Geothermal	GST	248	1.3	1128	1.6	-
Internal Combustion	Oil	15	0.1	3	-	8 bbls
Cogeneration	- -	0	0	0	0	-
Other	- -	350	1.9	8	-	-
Total		18701	100.0	72392	100.0	

Total Fuel Consumption

Coal (tons x 1000)		24552
Gas (MCF x 1000)		14994
Gas (equivalent oil bbls x 1000)		2548
Oil: distillate (bbls x 1000)	1994	
residual	2981	
crude	0	
Total oil		4975

Table 9C.11

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Arizona - New Mexico Power Area

Summer Capability

			Oil and Gas						Hydro 2/		
	Nuclear Steam	Coal Steam	Steam	Combined Cycle	Combust. Turbine	Geo-Thermal	Cogeneration	Other 1/	Conventional	Pumped Storage	Total Capability
1981	0	5945	2768	795	1444	0	0	15	649	137	11753
% Total	0	50.6	23.5	6.8	12.3	0	0	0.1	5.5	1.2	
1982	0	6190	2768	795	1592	0	0	15	649	137	12146
% Total	0	51.0	22.8	6.5	13.1	0	0	0.1	5.4	1.1	
1983	997	6433	2768	795	1494	98	0	15	649	137	13386
% Total	7.4	48.2	20.7	5.9	11.2	0.7	0	0.1	4.8	1.0	
1984	1697	6557	2768	795	1494	98	0	15	649	137	14210
% Total	11.9	46.1	19.5	5.6	10.5	0.7	0	0.1	4.6	1.0	
1985	1994	7025	2768	795	1640	98	0	15	649	137	15121
% Total	13.2	46.5	18.3	5.3	10.8	0.6	0	0.1	4.3	0.9	
1986	2694	7057	2768	795	1492	148	0	15	649	137	15755
% Total	17.1	44.8	17.6	5.0	9.5	0.9	0	0.1	4.1	0.9	
1987	2991	7817	2768	795	1492	148	0	15	649	137	16812
% Total	17.8	46.5	16.5	4.7	8.9	0.8	0	0.1	3.9	0.8	
1988	2991	8517	2768	795	1492	198	0	15	649	137	17562
% Total	17.0	48.5	15.8	4.5	8.5	1.1	0	0.1	3.7	0.8	
1989	2991	8659	2705	795	1492	198	0	15	649	137	17641
% Total	17.0	49.1	15.3	4.5	8.1	1.1	0	0.1	3.7	0.8	
1990	2991	9294	2582	793	1492	248	0	365	649	287	18701
% Total	16.0	49.7	13.8	4.2	8.0	1.3	0	2.0	3.5	1.5	

1/ Other capability includes wind and oil-fired diesel generation (15 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

Table 9C.12

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Arizona - New Mexico Power Area

Winter Capability

			Oil and Gas						Hydro 2/		
	Nuclear Steam	Coal Steam	Steam	Combined Cycle	Combust. Turbine	Geo-Thermal	Cogeneration	Other 1/	Conventional	Pumped Storage	Total Capability
1981	0	5887	2770	807	1613	0	0	15	602	137	11831
% Total	0	49.8	23.4	6.8	13.6	0	0	0.1	5.1	1.2	
1982	0	6202	2770	807	1461	48	0	15	602	137	12042
% Total	0	51.5	23.0	6.7	12.1	0.4	0	0.1	5.0	1.1	
1983	997	6443	2770	807	1511	98	0	15	602	137	13380
% Total	7.5	48.2	20.7	6.0	11.3	0.7	0	0.1	4.5	1.0	
1984	1697	6790	2770	807	1661	98	0	15	602	137	14577
% Total	11.6	46.6	19.0	5.5	11.4	0.7	0	0.1	4.1	0.9	
1985	1994	7057	2770	807	1509	148	0	15	602	137	15039
% Total	13.3	46.9	18.4	5.4	10.1	1.7	0	0.1	4.0	0.9	
1986	2694	7057	2770	807	1509	148	0	15	602	137	15739
% Total	17.1	44.8	17.6	5.1	9.6	0.9	0	0.1	3.8	0.9	
1987	2991	7817	2770	807	1509	148	0	15	602	137	16796
% Total	17.8	46.5	16.5	4.8	9.0	0.9	0	0.1	3.6	0.8	
1988	2991	8517	2707	807	1509	198	0	15	602	137	17483
% Total	17.1	48.7	15.5	4.6	8.6	1.1	0	0.1	3.4	0.8	
1989	2991	8659	2620	805	1509	198	0	15	602	137	17536
% Total	17.1	49.4	14.9	4.6	8.6	1.1	0	0.1	3.4	0.8	
1990	2991	9294	2584	805	1509	248	0	365	604	287	18687
% Total	16.0	49.7	13.8	4.3	8.1	1.3	0	2.0	3.2	1.5	

1/ Other capability includes solar and oil-fired diesel generation (15 MW each year).
2/ Hydrolectric capability based on adverse water conditions.

Table 9C.13

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1982-1985

ARIZONA-NEW MEXICO AREA (REGION 26)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	14001	13870	14831	14811	15801	15929	17111	16893
2. PEAK DEMAND	9509	6873	9930	7193	10409	7694	11191	8287
3. PLANNED RESERVES (1-2)	4492	6997	4901	7618	5392	8235	5920	8606
4. PLANNED RESERVES (%) (3/2)X100	47.2	101.8	49.4	105.9	51.8	107.0	52.9	103.8
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-1827	-1865	-1800	-1922	-2077	-1987	-2137	-2244
6. TOTAL CAPABILITY (1+5)	12174	12005	13031	12889	13724	13942	14974	14649
7. TOTAL RESERVES (6-2)	2665	5132	3101	5696	3315	6248	3783	6362
8. TOTAL RESERVES (%) (7/2)X100	28.0	74.7	31.2	79.2	31.8	81.2	33.8	76.8
9. SCHEDULED MAINTENANCE 1/	154	1845	163	1970	174	2119	188	2247
10. CAPABILITY AFTER MAINTENANCE (6-9)	12020	10160	12868	10919	13550	11823	14786	12402
11. RESERVES AFTER MAINTENANCE (10-2)	2511	3287	2938	3726	3141	4129	3595	4115
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	26.4	47.8	29.6	51.8	30.2	53.7	32.1	49.7
13. FULL FORCED OUTAGES 1/	574	416	605	444	648	478	702	507
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	11446	9744	12263	10475	12902	11345	14084	11895
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1937	2871	2333	3282	2493	3651	2893	3608
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	20.4	41.8	23.5	45.6	24.0	47.5	25.9	43.5
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	252	374	267	400	284	430	308	456
18. ACTUAL CAPABILITY (14-17)	11194	9370	11993	10075	12618	10915	13776	11439
19. ACTUAL RESERVES (18-2)	1685	2497	2063	2882	2209	3221	2585	3152
20. ACTUAL RESERVES (%) (19/2)X100	17.7	36.3	20.8	40.1	21.2	41.9	23.1	38.0

POSSIBLE NUCLEAR UNIT DELAYS ESTIMATED BY DOE

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. POSSIBLE NUCLEAR DELAYS	0	0	997	997	997	997	0	0
22. ACTUAL CAPABILITY WITH NUCLEAR DELAYS (18-21)	11194	9370	10996	9078	11621	9918	13776	11439
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (22-1)	1685	2497	1065	1885	1212	2224	2585	3152
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2)X100	17.7	36.3	10.7	26.2	11.6	28.9	23.1	38.0

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
25. POSSIBLE COAL DELAYS	472	0	0	0	210	0	350	0
26. ACTUAL CAPABILITY W/NUCLEAR & COAL DELAYS (22-25)	10722	9370	10996	9078	11411	9918	13426	11439
27. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (26-2)	1213	2497	1065	1885	1002	2224	2235	3152
28. ACTUAL RESERVES (%) W/NUCLEAR & COAL DELAYS	12.8	36.3	10.7	26.2	9.6	28.9	20.0	38.0

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

Table 9C.14

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1986-1990

ARIZONA-NEW MEXICO AREA (REGION 26)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	17565	17645	18827	18807	19331	19248	19338	19229	20572	20554
2. PEAK DEMAND	11817	8679	12346	9052	12911	9426	13454	9828	13998	10218
3. PLANNED RESERVES (1-2)	5748	8966	6481	9755	6420	9822	5884	9401	6574	10336
4. PLANNED RESERVES (%) (3/2)X100	48.6	103.3	52.5	107.8	49.7	104.2	43.7	95.7	47.0	101.2
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-2278	-2446	-2398	-2566	-2032	-1850	-1540	-1708	-1618	-1787
6. TOTAL CAPABILITY (1+5)	15287	15199	16429	16241	17299	17398	17798	17521	18954	18767
7. TOTAL RESERVES (6-2)	3470	6520	4083	7189	4388	7972	4344	7693	4956	8549
8. TOTAL RESERVES (%) (7/2)X100	29.4	75.1	33.1	79.4	34.0	84.6	32.3	78.3	35.4	83.7
9. SCHEDULED MAINTENANCE 1/	193	2347	207	2501	213	2560	213	2557	226	2734
10. CAPABILITY AFTER MAINTENANCE (6-9)	15094	12852	16222	13740	17086	14838	17585	14964	18728	16033
11. RESERVES AFTER MAINTENANCE (10-2)	3277	4173	3876	4688	4175	5412	4131	5136	4730	5815
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	27.7	48.1	31.4	51.8	32.3	57.4	30.7	52.3	33.8	56.9
13. FULL FORCED OUTAGES 1/	720	529	772	564	793	577	793	577	843	617
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	14374	12323	15450	13176	16293	14261	16792	14387	17885	15416
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2557	3644	3104	4124	3382	4835	3338	4559	3887	5198
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	21.6	42.0	25.1	45.6	26.2	51.3	24.8	46.4	27.8	50.9
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	316	476	339	508	348	520	348	519	370	555
18. ACTUAL CAPABILITY (14-17)	14058	11847	15111	12668	15945	13741	16444	13868	17515	14861
19. ACTUAL RESERVES (18-2)	2241	3168	2765	3616	3034	4315	2990	4040	3517	4643
20. ACTUAL RESERVES (%) (19/2)X100	19.0	36.5	22.4	39.9	23.5	45.8	22.2	41.1	25.1	45.4

POSSIBLE NUCLEAR UNIT DELAYS ESTIMATED BY DOE

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. POSSIBLE NUCLEAR DELAYS	997	997	0	0	0	0	0	0	0	0
22. ACTUAL CAPABILITY WITH NUCLEAR DELAYS (18-21)	13061	10850	15111	12668	15945	13741	16444	13868	17515	14861
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (22-2)	1244	2171	2765	3616	3034	4315	2990	4040	3517	4643
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2)X100	10.5	25.0	22.4	39.9	23.5	45.8	22.2	41.1	25.1	45.4

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
25. POSSIBLE COAL DELAYS	40	0	690	340	835	340	340	340	675	0
26. ACTUAL CAPABILITY W/NUCLEAR & COAL DELAYS (22-25)	13021	10850	14421	12328	15110	13401	16104	13528	16840	14861
27. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (26-2)	1204	2171	2075	3276	2199	3975	2650	3700	2842	4643
28. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (%)	10.2	25.0	16.8	36.2	17.0	42.2	19.7	37.6	20.3	45.4

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

[redacted]

D. Southern California - Nevada Power Area

Electric Region 27

The major electric utilities in the Southern California - Nevada Power Area (S.CA - NV) are the Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), Los Angeles Department of Water and Power (LADWP), and Nevada Power Company (NPC).

Historical Perspective

The 1980 annual peak demand for this summer peaking region occurred in July and was higher than forecasted due to lack of intra-regional load diversity. However, the 1980 energy requirements increased negligibly over 1979 and were less than the 1978 level.

Table 9D.1

1980 Load Growth

Southern California - Nevada Power Area

	1980
Energy Load (Gwh)	102309
Growth Rate from 1979 (%)	0.3
Peak Demand (MW)	21102
Growth Rate from 1979 (%)	2.9
Load Factor (%)	55.3

Exclusive of Nevada, the 1980 load for Southern California was less than for 1979. For only the second time in 20 years, electricity consumption for the entire state of California was less than that of the previous year. Table 9D.2 indicates that actual reserve margins for the area were adequate during the 1980 peak period. Of the total installed generating capacity for the area, nearly 70 perent is fired by oil and/or natural gas.

Current Perspective

Projected reserve margins for the 1981 summer and winter peak load periods are expected to be adequate. Further anaylsis of the summer load-supply situation is presented in Appendix C.

As shown in the 1981 ERA-411 report, San Onofre Nuclear Unit No. 2 (1100 MW) was scheduled to be operational at full power by December 1981. However, the estimated in-service dates for Unit No. 2 and Unit No. 3 (1100 MW) have subsequently been delayed and, for purposes of this report, these units are assumed to be in commercial operation by the summer of 1982 and 1983, respectively.

Scheduled capacity additions during 1981 consist of 44 MW of small hydro installations, a 56 MW uprate of an existing oil-fired steam plant, and 60 MW of existing combustion turbine upratings.

Future Perspective

The utilities in the Southern California - Nevada Power Area forecast an average annual load growth rate of 2.8 percent in peak demand from 1981 to 1985 and 3.0 percent from 1986 through 1990. The average annual energy load growth projections are 2.8 percent for both periods (see Table 9D.4). Although reduced from the load forecast of a year ago, these projections are somewhat higher than actual growth rates experienced during the past several years.

[redacted]

For Southern California, the adopted load forecast presented in the California Energy Commission's (CEC) 1981 Biannual Report projects an average annual growth in energy load of approximately 1.5 percent through the 1980's. This is significantly lower than the utilities' projections. These Southern California utilities serve nearly 95 perent of the total Electric Region 27 load. The CEC forecast is used in determining the need for additional generating resources during the state's power plant site certification process..

The CEC has endorced policy preferences which emphasize electric supply priorities in the following order:

1. Additional conservation and power pooling
2. Geothermal and renewable resources
3. Cogeneration and interstate transfers
4. Fuel switching from oil to natural gas
5. Synthetic fuels and new hydro resorvoirs
6. Direct-fired coal

The Commission has been very active in promulgating a progressive policy of energy efficiency standards, generous tax credits for conservation and solar investments, and programs promoting load management and additional conservation. The CEC has examined alternative electricity supply sources for the state and has concluded that aggressive pursuit of the preferred supply source is feasible, less costly, easier to finance, more reliable, causes less adverse environmental impact, and achieves the Commission's expressed goal of reducing oil and gas consumption by 50 percent between 1979 and 1992.

SCE, the largest Southern California utility, has recently effected a policy change in its resource planning which places greater emphasis on alternative and renewable energy sources. This plan is aligned with the preferred resource scenario advocated by the CEC.

Generating capability additions for Electric Region 27 through 1990 include 465 MW of hydro, 710 MW of geothermal, 280 MW of cogeneration, 310 MW of solar, 120 MW of wind, and 130 MW of fuel cells. In addition, SCE and SDG&E have signed agreements to purchase electricity generated at Mexico's geothermal fields near Mexicali. Conventional resource additions planned through 1990 include the 2200 MW of San Onofre Nuclear Units No's. 2 & 3, 819 MW of joint participation in Palo Verda Nuclear Units No's. 1 - 3 in Arizona, and 4157 MW of coal-fired capability in southern Nevada, Utah, and Arizona.

Table 9D.5 shows the current schedule for planned additional units larger than 100 MW and the delay, if any, from the schedule of a year ago. The listing includes only those units for which the lead agency is a S.CA - NV utility. It should be noted that SCE's California Coal Unit No's. 1 - 3 (1500 MW) have been delayed approximately 3 years from the late 1980's to beyond 1990 due to reduced load projections.

In February 1981, Pacific Gas and Electric Company and SCE announced the withdrawal of their application before the California Public Utilities Commission to participate in the construction of NPC's proposed Harry Allen and Warner Valley coal-fired plants. The California utilities had planned to own 50 percent of Warner Valley and 92 percent of Harry Allen while NPC would be the lead agency for the project. NPC is currently soliciting new participants and the units remain in the region's resource plan. However, the probability of delays -- particularly for the earlier scheduled units -- and the possibility of cancellations have been increased because of the California utilities' withdrawal.

Tables 9D.6 and 9D.7 show the projected mix of generating capacity for summer and winter from 1981 through 1990. Capabilities are expressed on an ownership basis including joint participation in units outside the region. It is noteworthy that despite no additions of conventional oil-fired units, the region remains significantly dependent on oil and gas-fired capacity.

Tables 9D.8 and 9D.9 show projected capability, peak demand and reserve margins for 1982 through 1990 including the effect on actual reserves of possible additional delays of nuclear and coal units as estimated by the Staff. Generally, delays of one year

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were assumed for all scheduled nuclear units and six months for coal-fired units with an additional delay for the Harry Allen and Warner Valley projects. Assuming the accuracy of the utilities' load forecasts and the continuation of historical average outage rates, the summer power supply situation could become marginal in the late 1980's. Delays in construction of nuclear or coal-fired resources without the substitution of alternative energy sources would most likely result in additional fuel oil consumption.

Proposed bulk power line additions for the region through 1990 consist of 243 miles of 230 KV line, 756 miles of 345 KV line, 1036 miles of 500 KV line, and 986 miles of 1000 KV (±500 KV) DC line. The DC line is scheduled to deliver coal-fired capacity from Utah to Southern California in the late 1980's. Also, the 580 mile existing 800 KV DC line from the Pacific Northwest to Sylmar is scheduled to be upgraded to 1000 KV DC in 1985.

Table 9D.2

ACTUAL CAPABILITY (MW) AND RESERVES (MW and Percent) - 1980
Southern California - Nevada Power Area (Region 27)

	Summer Peak
1. Planned Capability	24125
2. Peak Demand	21102
3. Planned Reserves (1-2)	3023
4. Planned Reserves (%) (3/2) x100	14.3
5. Net Transactions (Imports - Exports)	1674
6. Total Capability (1+5)	25799
7. Total Reserves (6-2)	4697
8. Total Reserves (%) (7/2) x100	22.3
9. Scheduled Maintenance	460
10. Capability After Maintenace (6-9)	25339
11. Reserves After Maintenance (10-2)	4237
12. Reserves After Maintenance (%) (11/2) x100	20.1
13. Full Forced Outage	116
14. Capability After Forced Outage (10-13)	25223
15. Reserves After Forced Outage (14-2)	4121
16. Reserves After Forced Outage (%) (15/2) x100	19.5
17. Other Unavailable Capability	78
18. Actual Capability (14-17)	25145
19. Actual Reserves (18-2)	4043
20. Actual Reserves (%) (19/2) x100	19.2

Table 9D.3

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
SOUTHERN CALIFORNIA-NEVADA AREA (REGION 27)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	22020	22420
2. PEAK DEMAND	21189	16507
3. PLANNED RESERVES (1-2)	831	5913
4. PLANNED RESERVES (%) (3/2)X100	3.9	35.8
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	4442	3783
6. TOTAL CAPABILITY (1+5)	26462	26203
7. TOTAL RESERVES (6-2)	5273	9696
8. TOTAL RESERVES (%) (7/2)X100	24.9	58.7
9. SCHEDULED MAINTENANCE 1/	878	2623
10. CAPABILITY AFTER MAINTENANCE (6-9)	25584	23580
11. RESERVES AFTER MAINTENANCE (10-2)	4395	7073
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	20.7	42.8
13. FULL FORCED OUTAGES 1/	947	1188
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	24637	22392
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	3448	5885
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	16.3	35.7
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1123	1188
18. ACTUAL CAPABILITY (14-17)	23514	21204
19. ACTUAL RESERVES (18-2)	2325	4697
20. ACTUAL RESERVES (%) (19/2)X100	11.0	28.5

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Table 9D.4

PROJECTED ENERGY AND DEMAND GROWTH RATES
Southern California - Nevada Power Area

	Energy Requirements		Summer Peak Demand		Winter Peak Demand		Annual Load Factor (%)
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	
1981	106419	4.0	21189	0.4	16507	4.3	57.6
1982	108291	1.8	21836	3.1	16989	2.9	56.6
1983	113318	4.6	22334	2.3	17303	1.8	57.9
1984	115994	2.4	22986	2.9	17678	2.2	57.6
1985	118807	2.4	23679	3.0	18297	3.5	57.3
% Growth 1981-1985		2.8		2.8		2.6	
1986	122108	2.8	24440	3.2	18911	3.4	57.0
1987	125495	2.8	25160	2.9	19520	3.2	56.9
1988	129054	2.8	25925	3.0	19961	2.3	56.8
1989	132522	2.7	26786	3.3	20592	3.2	56.5
1990	136572	3.1	27646	3.2	20943	1.7	56.4
% Growth 1986-1990		2.8		3.1		2.6	
% Growth 1981-1990		2.8		3.0		2.7	

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Table 9D.5

PLANNED SIGNIFICANT ADDITIONS TO GENERATING CAPACITY

Southern California - Nevada Power Area

Unit Name & Number	Type	Capability (MW)	Scheduled In-service Date	Delay Since Last Year (Months)[1]
San Onofre 2	Nuclear	1100	6/82[2]	8
Reid Gardner 4	Coal	250[3]	5/83	
San Onofre 3	Nuclear	1100	7/83[2]	6
Warner Valley 1	Coal	250[3]	5/85	
Warner Valley 2	Coal	250[3]	5/86	
Harry Allen 1	Coal	500[3]	5/86	
Intermountain 1	Coal	750[3]	7/86	
Dinkey Creek	Hydro	120	8/86	
Balsom Meadow	Hydro	200	8/86	
Harry Allen 2	Coal	500[3]	5/87	
Intermountain 2	Coal	750[3]	7/87	
Harry Allen 3	Coal	500[3]	5/88	
Intermountain 3	Coal	750[3]	7/88	
Harry Allen 4	Coal	500[3]	5/89	
White Pine 1	Coal	500[3]	6/89	
SCE Cogeneration	Cogen.	120	6/89	
Intermountain 4	Coal	750[3]	7/89	
White Pine 2	Coal	500[3]	6/90	
SCE Geothermal	Geo.	153	6/90	

[1] Number of months, if any, that the unit has been delayed from the schedule in the 1980 Electric Power Supply and Demand Report.

[2] Estimated present in-service dates for San Onofre 2 & 3 have been delayed since submission of the April 1981 ERA-411 data by approximately 6 months from those dates listed.

[3] A portion of this unit is owned by, and will be delivered to, utilities outside of S. CA-NV.

Table 9D.6

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Southern California - Nevada Power Area

Summer Capability

	Nuclear Steam	Coal Steam	Oil and Gas			Geo-Thermal	Cogeneration	Other 1/	Hydro 2/		Total Capability
			Steam	Combined Cycle	Combust. Turbine				Conventional	Pumped Storage	
1981	436	3871	14749	1137	1445	10	85	30	2261	621	24645
% Total	1.8	15.7	59.8	4.6	5.9	0.0	0.3	0.1	9.2	2.5	
1982	1536	3864	14749	1137	1515	10	110	33	2389	621	25964
% Total	5.9	14.9	56.8	4.4	5.8	0.0	0.4	0.1	9.2	2.4	
1983	2909	3838	14704	1137	1515	75	135	46	2509	621	27489
% Total	10.6	14.0	53.5	4.1	5.5	0.3	0.5	0.2	9.1	2.3	
1984	3182	3852	14683	1137	1515	145	135	46	2395	621	27711
% Total	11.5	13.9	53.0	4.1	5.5	0.5	0.5	0.2	8.6	2.2	
1985	3182	3828	14683	1137	1515	194	235	68	2390	621	27853
% Total	11.4	13.7	52.7	4.1	5.4	0.7	0.8	0.2	8.6	2.2	
1986	3455	4264	14683	1137	1515	282	235	112	2451	621	28755
% Total	12.0	14.8	51.1	4.0	5.3	1.0	0.8	0.4	8.5	2.2	
1987	3455	4737	14611	1137	1515	354	235	140	2446	621	29251
% Total	11.8	16.2	50.0	3.9	5.2	1.2	0.8	0.5	8.4	2.1	
1988	3455	5374	14495	1137	1515	515	235	310	2471	621	30128
% Total	11.5	17.8	48.1	3.8	5.0	1.7	0.8	1.0	8.2	2.1	
1989	3455	6425	14323	1137	1515	567	355	415	2505	621	31318
% Total	11.0	20.5	45.7	3.6	4.8	1.8	1.1	1.3	8.0	2.0	
1990	3455	7155	14237	1137	1515	720	355	590	2520	621	32305
% Total	10.7	22.1	44.1	3.5	4.7	2.2	1.1	1.8	7.8	1.9	

1/ Other capability includes solar, wind, fuel cell, and oil-fired diesel generation (30 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

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Table 9D.7

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Southern California - Nevada Power Area

Winter Capability

			Oil and Gas						Hydro 2/		
	Nuclear Steam	Coal Steam	Steam	Combined Cycle	Combust. Turbine	Geo-Thermal	Cogeneration	Other 1/	Conventional	Pumped Storage	Total Capability
1981	436	3871	14748	1170	1578	10	88	30	2299	621	24851
% Total	1.8	15.6	59.3	4.7	6.3	0.0	0.4	0.1	9.3	2.5	
1982	1536	3842	14748	1170	1648	10	113	33	2293	621	26014
% Total	5.9	14.8	56.7	4.5	6.3	0.0	0.4	0.1	8.8	2.4	
1983	2909	3827	14703	1170	1648	75	138	46	2530	621	27667
% Total	10.5	13.8	53.1	4.2	6.0	0.3	0.5	0.2	9.1	2.2	
1984	3182	3581	14682	1170	1648	145	138	46	2421	621	27634
% Total	11.5	13.0	53.1	4.2	6.0	0.5	0.5	0.2	8.8	2.2	
1985	3182	3733	14682	1170	1648	194	238	68	2463	621	27999
% Total	11.4	13.3	52.4	4.2	5.9	0.7	0.9	0.2	8.8	2.2	
1986	3455	4264	14682	1170	1648	282	238	112	2474	621	28946
% Total	11.9	14.7	50.7	4.0	5.7	1.0	0.8	0.4	8.5	2.1	
1987	3455	4737	14610	1170	1648	354	238	140	2459	621	29432
% Total	11.7	16.1	49.6	4.0	5.6	1.2	0.8	0.5	8.4	2.1	
1988	3455	5374	14494	1170	1648	515	238	310	2490	621	30315
% Total	11.4	17.7	47.8	3.9	5.4	1.7	0.8	1.0	8.2	2.0	
1989	3455	6425	14322	1170	1648	567	358	415	2499	621	31480
% Total	11.0	20.4	45.5	3.7	5.2	1.8	1.1	1.3	7.9	2.0	
1990	3455	7155	14236	1170	1648	720	358	590	2499	621	32452
% Total	10.6	22.0	43.9	3.6	5.1	2.2	1.1	1.8	7.7	1.9	

1/ Other capability includes solar, wind, fuel cell, and oil-fired diesel generation (30 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

Table 9D.8

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1982-1985
SOUTHERN CALIFORNIA-NEVADA AREA (REGION 27)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	23609	23589	25140	25265	25081	25090	25038	25086
2. PEAK DEMAND	21836	16989	22334	17303	22986	17678	23679	18297
3. PLANNED RESERVES (1-2)	1773	6600	2806	7962	2095	7412	1359	6789
4. PLANNED RESERVES (%) (3/2)X100	8.1	38.8	12.6	46.0	9.1	41.9	5.7	37.1
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	4311	3891	4425	3984	4787	4256	4880	4479
6. TOTAL CAPABILITY (1+5)	27920	27480	29565	29249	29868	29346	29918	29564
7. TOTAL RESERVES (6-2)	6084	10491	7231	11946	6882	11668	6239	11267
8. TOTAL RESERVES (%) (7/2)X100	27.9	61.8	32.4	69.0	29.9	66.0	26.3	61.5
9. SCHEDULED MAINTENANCE 1/	897	2760	955	2956	953	2936	951	2935
10. CAPABILITY AFTER MAINTENANCE (6-9)	27023	24720	28610	26293	28915	26410	28967	26629
11. RESERVES AFTER MAINTENANCE (10-2)	5187	7731	6276	8990	5929	8732	5288	8332
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	23.8	45.5	28.1	52.0	25.8	49.4	22.3	45.5
13. FULL FORCED OUTAGES 1/	1015	1250	1081	1339	1078	1330	1077	1330
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	26008	23470	27529	24954	27837	25080	27890	25299
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	4172	6481	5195	7651	4851	7402	4211	7002
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	19.1	38.1	23.3	44.2	21.1	41.9	17.8	38.3
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1204	1250	1282	1339	1279	1330	1277	1330
18. ACTUAL CAPABILITY (14-17)	24804	22220	26247	23615	26558	23750	26613	23969
19. ACTUAL RESERVES (18-2)	2968	5231	3913	6312	3572	6072	2934	5672
20. ACTUAL RESERVES (%) (19/2)X100	13.6	30.8	17.5	36.5	15.5	34.3	12.4	31.0

POSSIBLE NUCLEAR UNIT DELAYS ESTIMATED BY DOE

21. POSSIBLE NUCLEAR DELAYS	1100	1100	1373	1373	273	273	0	0
22. ACTUAL CAPABILITY WITH NUCLEAR DELAYS (18-21)	23704	21120	24874	22242	26285	23477	26613	23969
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (22-1)	1868	4131	2540	4939	3299	5799	2934	5672
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2)X100	8.6	24.3	11.4	28.5	14.4	32.8	12.4	31.0

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

25. POSSIBLE COAL DELAYS	0	0	81	0	0	0	125	125
26. ACTUAL CAPABILITY W/NUCLEAR & COAL DELAYS (22-25)	23704	21120	24793	22242	26285	23477	26488	23844
27. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (26-2)	1868	4131	2459	4939	3299	5799	2809	5547
28. ACTUAL RESERVES (%) W/NUCLEAR & COAL DELAYS	8.6	24.3	11.0	28.5	14.4	32.8	11.9	30.3

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Table 9D.9

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1986-1990
SOUTHERN CALIFORNIA-NEVADA AREA (REGION 27)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	26581	26522	27442	27464	28816	28667	30490	30495	31306	31537
2. PEAK DEMAND	24440	18911	25160	19520	25925	19961	26786	20592	27646	20973
3. PLANNED RESERVES (1-2)	2141	7611	2282	7944	2891	8706	3704	9903	3660	10564
4. PLANNED RESERVES (%) (3/2)X100	8.8	40.2	9.1	40.7	11.2	43.6	13.8	48.1	13.2	50.4
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	4146	3772	3306	2963	2187	1466	1071	692	833	554
6. TOTAL CAPABILITY (1+5)	30727	30294	30748	30427	31003	30133	31561	31187	32139	32091
7. TOTAL RESERVES (6-2)	6287	11383	5588	10907	5078	10172	4775	10595	4493	11118
8. TOTAL RESERVES (%) (7/2)X100	25.7	60.2	22.2	55.9	19.6	51.0	17.8	51.5	16.3	53.1
9. SCHEDULED MAINTENANCE 1/	1010	3103	1043	3213	1095	3354	1159	3568	1190	3686
10. CAPABILITY AFTER MAINTENANCE (6-9)	29717	27191	29705	27214	29908	26779	30402	27619	30949	28405
11. RESERVES AFTER MAINTENANCE (10-2)	5277	8280	4545	7694	3983	6818	3616	7027	3303	7432
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	21.6	43.8	18.1	39.4	15.4	34.2	13.5	34.1	11.9	35.5
13. FULL FORCED OUTAGES 1/	1143	1406	1180	1456	1239	1519	1311	1616	1346	1670
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	28574	25785	28525	25758	28669	25260	29091	26003	29603	26735
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	4134	6874	3365	6238	2744	5299	2305	5411	1957	5762
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X10	16.9	36.3	13.4	32.0	10.6	26.5	8.6	26.3	7.1	27.5
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1356	1406	1400	1456	1470	1519	1555	1616	1597	1670
18. ACTUAL CAPABILITY (14-17)	27218	24379	27125	24302	27199	23741	27536	24387	28006	25065
19. ACTUAL RESERVES (18-2)	2778	5468	1965	4782	1274	3780	750	3795	360	4092
20. ACTUAL RESERVES (%) (19/2)X10	11.4	28.9	7.8	24.5	4.9	18.9	2.8	18.4	1.3	19.5

POSSIBLE NUCLEAR UNIT DELAYS ESTIMATED BY DOE

21. POSSIBLE NUCLEAR DELAYS	273	273	0	0	0	0	0	0	0	0
22. ACTUAL CAPABILITY WITH NUCLEAR DELAYS (18-21)	26945	24106	27125	24302	27199	23741	27536	24387	28006	25065
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (22-2)	2505	5195	1965	4782	1274	3780	750	3795	360	4092
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2)X100	10.2	27.5	7.8	24.5	4.9	18.9	2.8	18.4	1.3	19.5

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

25. POSSIBLE COAL DELAYS	954	954	1224	1224	1299	1224	1654	1224	1025	520
26. ACTUAL CAPABILITY W/NUCLEAR & COAL DELAYS (22-25)	25991	23152	25901	23078	25900	22517	25882	23163	26981	24545
27. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (26-2)	1551	4241	741	3558	-25	2556	-904	2571	-665	3572
28. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (%)	6.3	22.4	2.9	18.2	-0.1	12.8	-3.4	12.5	-2.4	17.1

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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E. Northern California - Nevada Power Area

Electric Region 28

The area within the Northern California - Nevada Power Area (N.CA - NV) is comprised of the combined Pacific Gas and Electric Company (PG&E) and Sacramento Municipal Utility District (SMUD) service areas located in northern and central California, respectively. These utilities operate jointly -- that is, are centrally dispatched and serve more than 90 percent of the total load in Electric Region 28. In northern Nevada, the major utility is the Sierra Pacific Power Company (SPP).

Historical Perspective

This region experiences a summer peak dominated by air conditioning and irrigation pumping loads. The 1980 summer peak demand increased 1.6 percent from that experienced in 1979; annual energy load increased negligibly over 1979. Actual 1979-1980 growth rates in peak demand and energy were considerably below last year's projected growth rates of 5.5 percent for peak demand and 4.8 percent for energy.

Table 9E.1

1980 Load Growth

Northern California - Nevada Power Area

	1980
Energy Load (Gwh)	82708
Growth rate from 1979 (%)	0.0
Peak Demand (MW)	16277
Growth rate from 1979 (%)	1.6
Load Factor (%)	58.0

As of December 31, 1980, the region's generating capacity mix consisted of hydro (37.4 percent), oil/gas-fired (51.8 percent), geothermal (5.5 percent), and nuclear (5.3 percent) capacity.

PG&E's Diablo Canyon Nuclear Units Nos. 1 and 2 (2190 MW) remain off-line pending NRC licensing. To date, commercial operation of these units has been delayed nearly five years due to various licensing requirements. The licensing delay is principally due to additional seismological safety design requirements. Delayed installation of Diablo Canyon necessitated a PG&E purchase of 750 MW of short-term capacity from Southern California during the 1980 peak period. Actual reserves for PG&E were 8.8 percent in July 1980.

Current Perspective

Appendix C contains an analysis of the load-supply situation for summer 1981. The 1981 annual energy load for the region is expected to increase by 1.4 percent over 1980.

Scheduled additions to generating capacity during 1981 consist of 68 MW of cogeneration, 49 MW of combustion turbines, and 5 MW of geothermal capacity.

Future Perspective

Electric loads in N.CA - NV have been projected to increase at an average annual rate of 1.7 percent for peak demand and 1.2 percent for energy load during the 1981-85 period, although energy requirements are expected to decrease from 1981 to 1982. For the period 1986 through 1990, the forecasted average annual growth rate is 3.0 percent for peak demand and 3.4 percent for energy (see Table 9E.4).

The utilities' load projections are considerably lower than those of a year ago. The recently adopted California Energy Commission (CEC) forecast for Northern California projects an average annual growth rate for the PG&E/SMUD service area of 1.9 percent in peak demand and 1.0 percent in energy from 1979 through 1992.

Scheduled generating capacity additions from 1981 through 1990 consist of 2190 MW of nuclear (Diablo Canyon), 1211 MW geothermal, 1123 MW of pumped storage, 825 MW of conventional hydro, 1606 MW of coal, 480 MW of cogeneration, 130 MW of biomass and solid waste, and 17 MW of wind power.

Table 9E.5 lists the major additions greater than 100 MW in capacity along with the scheduled delay since last year. Tables 9E.6 and 9E.7 show the projected mix of generating capability by type for the summer and winter peak periods through 1990.

In conjunction with the reduced load projections, several coal-fired generating units which were scheduled for the latter half of the 1980's have recently been cancelled or delayed to beyond 1990. A total of 3200 MW of capacity is in this category, including Montezuma No's. 1 & 2 (1600 MW) which were scheduled by PG&E last year for 1986 and 1987, respectively. Additionally, a number of cogeneration projects and the Potrero No. 7 combined cycle unit have been deleted from PG&E's resource plan.

As noted in the Electric Region 27 section, the heretofore participating California utilities have withdrawn their application before the California Public Utilities Commission for joint ownership in the Harry Allen and Warner Valley coal-fired generating plants proposed for southern Nevada and Utah. The CEC adopted the position that Harry Allen and Warner Valley are not needed by the California utilities since other preferred resource options are available and that the decision to proceed with this project is pivotal in deciding if the conventional or the alternative path of conservation and renewables will be pursued. For PG&E, energy sources which are reasonably expected to be available (by the CEC) will permit PG&E to exceed oil and gas displacement goals without Harry Allen and Warner Valley. This action increases the possibility of delays for these plants and leaves their ownership uncertain, thus making the availability of this power questionable for Electric Regions 27 and 28.

Tables 9E.8 and 9E.9 show projected reserve margins for 1982 through 1990. Also shown are potential effects on actual resere margins of assumed delays of one year for nuclear units, six months for most coal-fired units, and an additional delay for the Harry Allen and Warner Valley plants.

Scheduled transmission additions from 1981 through 1990 consist of 802 miles of 230 KV line, 596 miles of 345 KV line -- mainly associated with SPP's Valmy plant, and 341 miles of 500 KV line including a 289 mile additional connection with the Northwest in 1989.

The 52 mile Gates to Gregg 500 KV line has been delayed an additional four years due to regulatory rejection of the original proposal. Also, expected regulatory delay of new transmission associated with development at the Geysers could cause curtailments of geothermal generation resulting in increased oil consumption.

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Table 9E.2

ACTUAL CAPABILITY (MW) AND RESERVES (MW and Percent) - 1980
Northern California - Nevada Power Area (Region 28)

	Summer Peak
1. Planned Capability	17375
2. Peak Demand	16277
3. Planned Reserves (1-2)	1098
4. Planned Reserves (%) (3/2) x100	6.7
5. Net Transactions (Imports - Exports)	2220
6. Total Capability (1+5)	19595
7. Total Reserves (6-2)	3318
8. Total Reserves (%) (7/2) x100	20.4
9. Scheduled Maintenance	21
10. Capability After Maintenace (6-9)	19574
11. Reserves After Maintenance (10-2)	3297
12. Reserves After Maintenance (%) (11/2) x100	20.3
13. Full Forced Outage	1539
14. Capability After Forced Outage (10-13)	18035
15. Reserve After Forced Outage (14-2)	1758
16. Reserve After Forced Outage (%) (15/2) x100	10.8
17. Other Unavailable Capability	36
18. Actual Capability (14-17)	17999
19. Actual Reserves (18-2)	1722
20. Actual Reserves (%) (19/2) x100	10.6

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Table 9E.3

CURRENT CAPABILITY (MW) AND RESERVES (MW AND PERCENT) - 1981
NORTHERN CALIFORNIA-NEVADA AREA (REGION 28)

	1981 SUMMER PEAK	1981/82 WINTER PEAK
1. PLANNED CAPABILITY	16859	16738
2. PEAK DEMAND	16662	12982
3. PLANNED RESERVES (1-2)	197	3756
4. PLANNED RESERVES (%) (3/2)X100	1.2	28.9
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	1358	299
6. TOTAL CAPABILITY (1+5)	18217	17037
7. TOTAL RESERVES (6-2)	1555	4055
8. TOTAL RESERVES (%) (7/2)X100	9.3	31.2
9. SCHEDULED MAINTENANCE 1/	0	1121
10. CAPABILITY AFTER MAINTENANCE (6-9)	18217	15916
11. RESERVES AFTER MAINTENANCE (10-2)	1555	2934
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	9.3	22.6
13. FULL FORCED OUTAGES 1/	303	736
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	17914	15180
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	1252	2198
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	7.5	16.9
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1028	770
18. ACTUAL CAPABILITY (14-17)	16886	14410
19. ACTUAL RESERVES (18-2)	224	1428
20. ACTUAL RESERVES (%) (19/2)X100	1.3	11.0

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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Table 9E.4

PROJECTED ENERGY AND DEMAND GROWTH RATES

Northern California - Nevada Power Area

	Energy Requirements		Summer Peak Demand		Winter Peak Demand		Annual Load Factor
	(GWH)	Growth (%)	(MW)	Growth (%)	(MW)	Growth (%)	(%)
1981	83847	1.4	16662	2.4	12982	2.6	57.5
1982	82960	-1.1	16666	0.0	12871	-0.9	56.8
1983	83801	1.0	16851	1.1	12770	-0.8	56.8
1984	85515	2.0	17307	2.7	13079	2.4	56.4
1985	88088	3.0	17833	3.0	13478	3.1	56.4
% Growth 1981-1985		1.2		1.7		0.9	
1986	91660	4.1	18205	2.1	14014	4.0	57.5
1987	95437	4.1	18755	3.0	14605	4.2	58.1
1988	89807	3.6	19404	3.5	15135	3.6	58.2
1989	102422	3.6	20044	3.3	15649	3.4	58.3
1990	104971	2.5	20468	2.1	16055	2.6	58.5
% Growth 1986-1990		3.4		3.0		3.5	
% Growth 1981-1990		2.5		2.3		2.4	

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Table 9E.5

PLANNED SIGNIFICANT ADDITIONS TO GENERATING CAPACITY

Northern California - Nevada Power Area

Unit Name & Number	Type	Capability (MW)	Scheduled In-service Date	Delay Since Last Year (Months)[1]
Valmy 1	Coal	250[2]	10/81	
New Melones	Hydro	300	1/82	11
Diablo Canyon 1	Nuclear	1084	3/82[3]	
Helms 1	Pumped Storgage	374	7/82	7
Geysers 17	Geothermal	110	8/82	1
Helms 2	Pumped Storage	374	9/82	5
Helms 3	Pumped Storage	375	10/82	5
Geysers 18	Geothermal	110	10/82	
Diablo Canyon 2	Nuclear	1106	11/82[3]	15
Kerckhoff 2	Hydro	151	10/83	
Geysers 16	Geothermal	110	11/83	
Valmy 2	Coal	250[2]	10/84	
Geysers 20	Geothermal	110	12/84	-9[4]
Texaco	Cogeneration	210	1/87	
Geysers 22	Geothermal	110	6/88	
Geysers 21	Geothermal	110	8/88	25
Geysers 23	Geothermal	110	6/89	

1/ Number of months, if any, that the unit has been delayed from the schedule in the 1980 Electric Power Supply and Demand Report.

2/ 50 percent (125 MW) of each Valmy unit is owned by, and will be delivered to, a utility in the Northwest Power Pool Area.

3/ Estimated present in-service dates for Diablo Canyon 1 & 2 have been delayed since submission of the April 1981 ERA-411 data. Approximately 8 months should be added to those dates listed.

4/ Negative number indicates advancement of a unit.

Table 9E.6

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Northern California - Nevada Power Area

Summer Capability

			Oil and Gas						Hydro 2/		
	Nuclear Steam	Coal Steam	Steam	Combined Cycle	Combust. Turbine	Geo-Thermal	Cogeneration	Other 1/	Conventional	Pumped Storage	Total Capability
1981	875	0	7775	0	538	908	200	50	5854	287	16487
% Total	5.3	0.0	47.2	0.0	3.3	5.5	1.2	0.3	35.5	1.7	
1982	1959	125	7775	0	538	1019	236	101	5947	658	18358
% Total	10.7	0.7	42.4	0.0	2.9	5.6	1.3	0.6	32.4	3.6	
1983	3065	295	7775	0	538	1239	288	101	6224	1188	20713
% Total	14.8	1.4	37.5	0.0	2.6	6.0	1.4	0.5	30.0	5.7	
1984	3065	295	7659	0	538	1514	315	181	6357	1189	21113
% Total	14.5	1.4	36.3	0.0	2.5	7.2	1.5	0.9	30.1	5.6	
1985	3065	483	7659	0	538	1679	315	183	6376	1188	21486
% Total	14.3	2.2	35.6	0.0	2.5	7.8	1.5	0.9	29.7	5.5	
1986	3065	776	7659	0	538	1679	315	183	6534	1188	21937
% Total	14.0	3.5	34.9	0.0	2.5	7.7	1.4	0.8	29.8	5.4	
1987	3065	1006	7659	0	538	1734	580	183	6594	1186	22545
% Total	13.6	4.5	34.0	0.0	2.4	7.7	2.6	0.8	29.2	5.3	
1988	3065	1236	7659	0	538	1899	580	185	6631	1204	22997
% Total	13.3	5.4	33.3	0.0	2.3	8.3	2.5	0.8	28.8	5.2	
1989	3065	1536	7479	0	538	2119	630	189	6686	1125	23367
% Total	13.1	6.6	32.0	0.0	2.3	9.1	2.7	0.8	28.6	4.8	
1990	3065	1606	7479	0	538	2119	680	197	6734	1125	23543
% Total	13.0	6.8	31.8	0.0	2.3	9.0	2.9	0.8	28.6	4.8	

1/ Other capability includes solar, wind, biomass and oil-fired diesel generation (50 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

Table 9E.7

PLANNED NET CAPABILITY AT THE TIME OF SEASONAL PEAK, BY TYPE (MW)

Northern California - Nevada Power Area

Winter Capability

			Oil and Gas						Hydro 2/		
	Nuclear Steam	Coal Steam	Steam	Combined Cycle	Combust. Turbine	Geo-Thermal	Cogeneration	Other 1/	Conventional	Pumped Storage	Total Capability
1981	903	125	7775	0	596	913	211	100	5450	193	16266
% Total	5.6	0.8	47.8	0.0	3.7	5.6	1.3	0.6	33.5	1.2	
1982	3093	125	7775	0	596	1239	263	101	5493	1276	19961
% Total	15.5	0.6	39.0	0.0	3.0	6.2	1.3	0.5	27.5	6.4	
1983	3093	295	7659	0	596	1404	315	101	5870	1083	20416
% Total	15.1	1.4	37.5	0.0	2.9	6.9	1.5	0.5	28.8	5.3	
1984	3093	420	7659	0	596	1624	315	181	5924	1083	20895
% Total	14.8	2.0	36.7	0.0	2.9	7.8	1.5	0.9	28.4	5.2	
1985	3093	483	7659	0	596	1679	315	183	5952	1083	21044
% Total	14.7	2.3	36.4	0.0	2.8	8.0	1.5	0.9	28.3	5.1	
1986	3093	776	7659	0	596	1679	370	183	5983	1083	21422
% Total	14.4	3.6	35.8	0.0	2.8	7.8	1.7	0.9	27.9	5.1	
1987	3093	1006	7659	0	596	1734	580	183	6018	1083	21952
% Total	14.1	4.6	34.9	0.0	2.7	7.9	2.6	0.8	27.4	4.9	
1988	3093	1236	7659	0	596	2009	580	185	6085	1083	22526
% Total	13.7	5.5	34.0	0.0	2.6	8.9	2.6	0.8	27.0	4.8	
1989	3093	1536	7479	0	596	2119	630	189	6135	1083	22860
% Total	13.5	6.7	32.7	0.0	2.6	9.3	2.8	0.8	26.8	4.7	
1990	3093	1606	7479	0	596	2119	680	197	6185	1083	23041
% Total	13.4	7.0	32.5	0.0	2.6	9.2	3.0	0.9	26.8	4.7	

1/ Other capability includes solar, wind, biomass, and oil-fired diesel generation (50 MW each year).
2/ Hydroelectric capability based on adverse water conditions.

Table 9E.8

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1982-1985
NORTHERN CALIFORNIA-NEVADA AREA (REGION 28)

	1982		1983		1984		1985	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	18855	20433	20861	20720	21282	21324	21989	21685
2. PEAK DEMAND	16666	12871	16851	12770	17307	13079	17833	13478
3. PLANNED RESERVES (1-2)	2189	7562	4010	7950	3975	8245	4156	8207
4. PLANNED RESERVES (%) (3/2)X100	13.1	58.8	23.8	62.3	23.0	63.0	23.3	60.9
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	833	-101	715	-253	559	-378	514	-378
6. TOTAL CAPABILITY (1+5)	19688	20332	21576	20467	21841	20946	22503	21307
7. TOTAL RESERVES (6-2)	3022	7461	4725	7697	4534	7867	4670	7829
8. TOTAL RESERVES (%) (7/2)X100	18.1	58.0	28.0	60.3	26.2	60.1	26.2	58.1
9. SCHEDULED MAINTENANCE 1/	151	1369	167	1388	170	1429	176	1453
10. CAPABILITY AFTER MAINTENANCE (6-9)	19537	18963	21409	19079	21671	19517	22327	19854
11. RESERVES AFTER MAINTENANCE (10-2)	2871	6092	4558	6309	4364	6438	4494	6376
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	17.2	47.3	27.0	49.4	25.2	49.2	25.2	47.3
13. FULL FORCED OUTAGES 1/	339	899	375	912	383	938	396	954
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	19198	18064	21034	18167	21288	18579	21931	18900
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2532	5193	4183	5397	3981	5500	4098	5422
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	15.2	40.3	24.8	42.3	23.0	42.1	23.0	40.2
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1150	940	1273	953	1298	981	1341	998
18. ACTUAL CAPABILITY (14-17)	18048	17124	19761	17214	19990	17598	20590	17902
19. ACTUAL RESERVES (18-2)	1382	4253	2910	4444	2683	4519	2757	4424
20. ACTUAL RESERVES (%) (19/2)X100	8.3	33.0	17.3	34.8	15.5	34.6	15.5	32.8

POSSIBLE NUCLEAR UNIT DELAYS ESTIMATED BY DOE

	1982 SUMMER	1982 WINTER	1983 SUMMER	1983 WINTER	1984 SUMMER	1984 WINTER	1985 SUMMER	1985 WINTER
21. POSSIBLE NUCLEAR DELAYS	1084	2190	1106	0	0	0	0	0
22. ACTUAL CAPABILITY WITH NUCLEAR DELAYS (18-21)	16964	14934	18655	17214	19990	17598	20590	17902
23. ACTUAL RESERVES WITH NUCLEAR DELAYS (22-1)	298	2063	1804	4444	2683	4519	2757	4424
24. ACTUAL RESERVES WITH NUCLEAR DELAYS (%) (23/2)X100	1.8	16.0	10.7	34.8	15.5	34.6	15.5	32.8

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

	1982 SUMMER	1982 WINTER	1983 SUMMER	1983 WINTER	1984 SUMMER	1984 WINTER	1985 SUMMER	1985 WINTER
25. POSSIBLE COAL DELAYS	0	0	170	0	0	125	63	63
26. ACTUAL CAPABILITY W/NUCLEAR & COAL DELAYS (22-25)	16964	14934	18485	17214	19990	17473	20527	17839
27. ACTUAL RESERVES W/NUCLEAR & COAL DELAYS (26-2)	298	2063	1634	4444	2683	4394	2694	4361
28. ACTUAL RESERVES (%) W/NUCLEAR & COAL DELAYS	1.8	16.0	9.7	34.8	15.5	33.6	15.1	32.4

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

BEST DOCUMENT AVAILABLE

Table 9E.9

FUTURE CAPABILITY (MW) AND RESERVES (MW AND PERCENT) 1986-1990
NORTHERN CALIFORNIA-NEVADA AREA (REGION 29)

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. PLANNED CAPABILITY	22073	21770	23050	22070	23476	22414	23546	22448	23652	22556
2. PEAK DEMAND	18205	14014	18755	14605	19404	15135	20044	15649	20468	16055
3. PLANNED RESERVES (1-2)	3868	7756	4295	7465	4072	7279	3502	6799	3184	6501
4. PLANNED RESERVES (%) (3/2)X100	21.2	55.3	22.9	51.1	21.0	48.1	17.5	43.4	15.6	40.5
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	485	-385	-108	-450	205	-35	404	322	716	565
6. TOTAL CAPABILITY (1+5)	22558	21385	22942	21620	23681	22379	23950	22770	24368	23121
7. TOTAL RESERVES (6-2)	4353	7371	4187	7015	4277	7244	3906	7121	3900	7066
8. TOTAL RESERVES (%) (7/2)X100	23.9	52.6	22.3	48.0	22.0	47.9	19.5	45.5	19.1	44.0
9. SCHEDULED MAINTENANCE 1/	177	1459	184	1479	188	1502	188	1504	189	1511
10. CAPABILITY AFTER MAINTENANCE (6-9)	22381	19926	22758	20141	23493	20877	23762	21266	24179	21610
11. RESERVES AFTER MAINTENANCE (10-2)	4176	5912	4003	5536	4089	5742	3718	5617	3711	5555
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	22.9	42.2	21.3	37.9	21.1	37.9	18.5	35.9	18.1	34.6
13. FULL FORCED OUTAGES 1/	397	958	415	971	423	986	424	988	426	992
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	21984	18968	22343	19170	23070	19891	23338	20278	23753	20618
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	3779	4954	3588	4565	3666	4756	3294	4629	3285	4563
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	20.8	35.4	19.1	31.3	18.9	31.4	16.4	29.6	16.0	28.4
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	1346	1001	1406	1015	1432	1031	1436	1033	1443	1038
18. ACTUAL CAPABILITY (14-17)	20638	17967	20937	18155	21638	18860	21902	19245	22310	19580
19. ACTUAL RESERVES (18-2)	2433	3953	2182	3550	2234	3725	1858	3596	1842	3525
20. ACTUAL RESERVES (%) (19/2)X100	13.4	28.2	11.6	24.3	11.5	24.6	9.3	23.0	9.0	22.0

POSSIBLE COAL UNIT DELAYS ESTIMATED BY DOE

	1986		1987		1988		1989		1990	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
21. POSSIBLE COAL DELAYS	356	356	586	586	586	586	656	586	426	356
22. ACTUAL CAPABILITY WITH COAL DELAYS (18-21)	20282	17611	20351	17569	21052	18274	21246	18659	21884	19224
23. ACTUAL RESERVES WITH COAL DELAYS (22-2)	2077	3597	1596	2964	1648	3139	1202	3010	1416	3169
24. ACTUAL RESERVES (%) WITH COAL DELAYS (23/2)X100	11.4	25.7	8.5	20.3	8.5	20.7	6.0	19.2	6.9	19.7

1/ SCHEDULED MAINTENANCE (EXCEPT FOR THE 1981 SUMMER), OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

GLOSSARY

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GLOSSARY

The purpose of this glossary is to define for the purposes of this report those terms which may be unfamiliar, or whose meaning may not be clear, to non-technical readers. It is not intended that this glossary replace technical dictionaries.

AVAILABILITY FACTOR

- the ratio of the time a machine or equipment is ready for or in service, to the total time interval under consideration. "Total time interval" refers to calendar time and is not affected by a unit being in service or not.

CAPABILITY

- a general term for the maximum load which a generating unit, power plant or system can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress. When used in reference to a system or plant, capability includes all generating units and is known as "installed capability". It includes the capability of units that may be temporarily inoperable because of maintenance, forced outage or other reasons, or only operable at less than full output.

  Summer net dependable planned capability refers to the capability during the summer peak period. This period usually occurs on most systems between June 1 and September 30; it may last for several days. It is expected that the unit, plant or system will be able to supply the stated power output for the duration of the peak period.

  Winter net dependable planned capability refers to the capability during the winter peak period. This period occurs on most systems between December 1 of any year and March 31 of the following year. It is expected that the unit, plant or system will be able to supply the stated power output for the duration of the peak period. Steam units and combustion turbines may have capabilities greater in winter than in summer, in those locations where the ambient temperature is significantly lower in winter than in summer.

CAPACITY

- the load for which a generating unit is rated. That is, the load which a unit has been designed to supply under strictly specified conditions relating to height above sea level, ambient temperature, cooling water temperature, fuel type and characteristics, condition of heat transfer surfaces, power factor, duration and constancy of the load to be carried and possibly other factors. This is a nominal value that may not correspond exactly to "capability". In general discussions of the ability of a system to supply electric power, "capacity" and "capability" are frequently used interchangeably. The magnitude of the difference between "capability" and "capacity" is usually not great.

CAPACITY (INOPERABLE)

- capacity which could not be operated for the period specified because of lack of fuel, lack of personnel, because it is in deactivated shut-down status or for similar reasons. This category does not include forced or scheduled outages.

CAPACITY FACTOR

- the ratio of the average demand on a machine or equipment for the period of time considered, to the capacity rating of the machine or equipment. The meaning can be extended to a plant or a system.

DEMAND

- the rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, expressed in kilowatts or other suitable unit, at a given instant or averaged over any designated period of time.

Coincident Demand--any demand that occurs simultaneously with any other demand; also the sum of any set of coincident demands.

Instantaneous Demand--the demand at any instant, usually determined from the reading of an indicating or recording instrument.

Integrated Demand--the demand averaged over a specified period, usually determined by an integrating demand meter or by the integration of a load curve.

Peak Demand--the greatest of a particular type of demand occurring within a specified period.

Noncoincident Demand--the sum of the individual maximum demands regardless of time of occurrence within a specified period, usually not more than 1 year.

DEMAND INTERVAL

- the period of time during which the electric energy flow is averaged in determining demand, such as 60-minute, 30-minute, or instantaneous.

DISTRIBUTION SYSTEM

- that portion of an electric system used to deliver electric energy from points on the transmission or bulk power system to the consumers.

DIVERSITY FACTOR

- the ratio of the sum of the noncoincident maximum demands of the various subdivisions of a system, or part of a system, to the maximum coincident demand of the whole system, or part under consideration.

DIVERSITY, LOAD

- the difference between the peak of coincident and noncoincident demands of two or more individual loads.

Seasonal Diversity--load diversity between two (or more) electric systems which occurs when their annual peaks are in different seasons of the year.

Time Zone Diversity--load diversity between electric systems in different time zones resulting from the time difference as it affects the demands for power.

ELECTRIC REGION

- A subarea of a Reliability Council area. The 29 Electric Regions in the Contiguous U.S. (plus one for Alaska) were established by ERA for the purposes of the Fuel Use Act and have proven useful for analyses of electric power supply adequacy and reliability.

ELECTRIC SYSTEM

- physically connected electric generating, transmission, and distribution facilities operated to provide electricity to customers. The facilities need not be all under control of a single organization, as the term is used in this report. Thus, for the purposes of this report the Detroit Edison Company is a system, Consumers Power Company is a system and the two together comprise a system. The term "utility" or "electric utility" is used in this report to describe a system under single control, whether privately-owned, publicly-owned or cooperatively-owned. Thus, the Los Angeles Department of Water and Power, a municipal organization, is an electric utility, as are the Tennessee Valley Authority, the Power Authority of the State of New York and the Louisville Gas & Electric Company, for example. The Tri-State G. & T. Association, Inc., is also a system and an electric utility in the sense that those terms are used in this report.

ENERGY

- that which does or is capable of doing work. It is measured in terms of the work it is capable of doing; electric energy is usually measured in kilowatt-hours or megawatt hours.

Economy Energy--electric energy produced from a source in one system and substituted for energy that would otherwise have been produced by a less economical source in another system.

Interchange Energy--electric energy received by one electric utility system in exchange for energy delivered to the other system at another time or place. Interchange is to be distinguished from a direct purchase or sale, although energy balances accumulated under interchange agreements are sometimes settled for in cash.

Net Energy For System--the electric energy requirements of a system, including losses, defined as: (1) net generation of the system, plus (2) energy received from others, less (3) energy delivered to other systems for resale.

Off-Peak Energy--electric energy supplied during periods of relatively low system demands as specified by the supplier.

On-Peak Energy--electric energy supplied during periods of relatively high system demands as specified by the supplier.

LOAD

- the amount of electric power demanded at a given point or from a given system.

Base Load--the minimum load in a stated period of time.

Connected Load--the sum of the ratings of the electric power consuming apparatus connected to the system, or part of the system, under consideration.

Interruptible Load--electric load which may be curtailed at the supplier's discretion, or in accordance with a contractual agreement.

Peak Load--the maximum load in a stated period of time.

Plant Factor--the ratio of the average demand on a power plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant.

LOSS

Electric System Loss--total electric energy loss in the electric system. It consists of transmission, transformation, and distribution losses, and unaccounted-for-energy-losses between sources of supply and points of delivery.

Energy Loss--the difference between energy input and output as a result of transfer of energy between two points.

Line Loss--energy loss and power loss on a transmission or distribution line.

No-Load-Loss--power and energy losses in an electric system, or portion thereof, when energized at rated voltage and frequency, but not supplying load.

NETWORK

- a system of transmission or distribution lines so connected and operated as to permit multiple power supply to any principal point on it.

NUCLEAR REACTOR

- an apparatus by means of which a fission chain reaction can be initiated, maintained, and controlled. Its essential component is a core with fissionable fuel. It usually has a moderator, reflectors, shielding, and control mechanisms.

OUTAGE

- the out-of-service condition of a generating unit, transmission line, or other facility.

Forced Outage—the shutdown of a generating unit, transmission line, or other facility, for emergency reasons. The nature of the emergency is such that the shutdown must be effected immediately or not later than the very next weekend.

Scheduled Outage (maintenance)—the shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule. The shutdown may be postponable within certain limits.

HEAT RATE

- a measure of generating station thermal efficiency, generally expressed as BTU per net kilowatt-hour. It is computed by dividing the total BTU content of the fuel burned (or of heat released from a nuclear reactor) by the resulting net kilowatt-hours generated.

INTERCONNECTION

- a transmission line, transformer or other device or equipment permitting a flow of energy between the facilities of two electric systems.

Emergency Interconnection—an interconnection established to meet an emergency need.

INTERTIE—same as INTERCONNECTION.

GENERATING UNIT

- an electric generation together with its prime mover.

GENERATION

- the act or process of producing electric energy from other forms of energy; also the amount of electric energy so produced.

Gross Generation—the total amount of electric energy produced by a generating station or stations, measured at the generator terminals.

Net Generation—gross generation less plant use.

Nonutility Generation—generation by producers having generating plants for the purpose of supplying electric power required by their own industrial, commercial, or military operations.

Utility Generation—generation by electric systems engaged in the business of selling or supplying electric energy for use by the general public.

POWER

- the time rate of transferring energy. The term is frequently used in a broad sense, as a commodity of capacity and energy, having only general association with the scientific meaning.

Electric Power—a term used in the electric power industry to mean inclusively power and energy.

Interruptible Power—power made available under agreements which permit curtailment or cessation of delivery by the supplier under conditions specified in the agreement.

POWER PLANT

- A location at which one or more generating units are located.

Base Load Plant—a power plant which is normally operated to provide base load and which, consequently, operates at essentially a constant load.

Fossil-Fuel Plant—an electric power plant utilizing fossil fuel, such as coal, lignite, oil or natural gas, as its source of energy.

Hydroelectric Plant—an electric power plant utilizing falling water for the motive force of its prime movers.

Nuclear Power Plant—an electric generating station utilizing the energy from a nuclear reactor as the source of power.

Peak Load Plant—a power plant which is normally operated to provide power during maximum load periods.

Power Plant (Generating Station)—a generating station at which are located prime movers, electric generators, and auxiliary equipment for producing electric energy.

Pumped Storage Plant—a power plant utilizing an arrangement whereby electric energy is generated for peak load use, by utilizing water pumped into an elevated storage reservoir usually during off-peak periods.

Run-of-River Plant—a hydroelectric power plant utilizing the flow of the stream as it occurs.

Steam-Electric Plant—an electric power plant utilizing steam for the motive force of its prime movers.

RESERVE MARGIN

- as used in this report, "Reserve Margin" is the difference between system capability at the time of peak demand and the system peak demand. When this difference is expressed as a percentage of the peak demand, the margin is called "Percent Reserve". The summer reserve margin and the winter reserve margin usually are different. When "Reserve Margin" or "Percent Reserve" are used without being qualified, the reference is to "Installed Reserve" (also called "Planned Reserve" in this report), meaning the difference between the sum of the capabilities of all units on the system, including those temporarily inoperable, and the system peak demand.

RESERVE (OPERATING)

- generating capacity (or capability) that can be made available to take load within a short time. The time limitation is usually stated to be "ten minutes or less" but in some instances may be as much as one-half hour. "Operating Reserve" consists of "Spinning Reserve" and "Non-Spinning Reserve". The Spinning Reserve is in operation and is connected to the bus. The Non-Spinning Reserve is capability that can be started, connected to the bus and loaded within the specified time limitation.

RESERVE (SPINNING)

- generating capacity (or capability) connected to the bus and ready to take load. This includes the capability of units running unloaded and the capability available in units that are loaded to less than their capability and which can be loaded further.

RESERVE (PLANNED)

- the reserve which is planned for a given peak load period. It includes allowances for all foreseeable contingencies.

RESERVE (ACTUAL)

- the estimated actual reserve at time of peak demand after deduction of all foreseeable capacity contingencies.

RESERVE (COLD)

- generating capability that requires several hours, or possibly a day, to bring into operation.

RESERVE (DE-ACTIVATED)

- generating capability which will take several weeks at best to become operable. This is capability that a system does not expect to operate under normal conditions because it is obsolescent, inefficient, may violate environmental quality restrictions, may require extensive maintenance, may require fuel not readily available, or for other reasons.

WATER CONDITIONS

- Adverse Water Conditions—water conditions which limit the output of hydroelectric generating units because of insufficient water supply or reduced head. Insufficient water supply may be due to low precipitation, diversion of water for purposes other than power pr[illegible]on or other reasons. The availability of [illegible] under adverse conditions is usually determin[illegible] analysis of historical studies extending c[illegible] long period of years. Adverse conditions may also result from reduced net head caused by high water on the downstream side of a plant.

- Average Water Conditions—conditions of precipitation and runoff which provide water for hydroelectric plants approximating the average amount and distribution available over a long time period, usually the period of record.

THERMAL

- a term used to identify a type of electric generating station or power plant, or the capacity or capability thereof, in which the source of energy for the prime mover is heat. The heat may be obtained from combustion of coal, oil, gas, waste or other material, from geothermal sources (heat from the earth's core) or from nuclear fission or other nuclear process. Heat for electric generation may also be obtained from solar radiation, but generation using that source is usually referred to as one of the types of "solar energy".

TRANSMISSION

- the movement or transfer of electric energy in bulk. Ordinarily the transmission movement is considered to end when the voltage level of the energy is transformed for distribution to ultimate consumers. The term is also used to refer to the aggregate of system transmission facilities.

Transmission Line Capacity—the maximum continuous rating of a transmission line. The rating may be limited by thermal considerations, capacity of associated equipment, voltage regulation, system stability or other factors.

Transmission System—an interconnected group of electric transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points at which it is transformed for delivery to ultimate consumers, or is delivered to electric systems of others.

APPENDIX A

Appendix A

The Reliability Councils and the Annual Long-Range Coordinated Planning Report (ERA-411)

Twelve regional electric reliability councils were established during the period 1963 through 1969. These were ultimately consolidated to the present nine councils. Each council is a voluntary association of electric utilities in a geographic area of North America, defined mainly by historic operating practices and patterns of interconnection growth. The nine councils together, covering the contiguous United States, comprise the National Electric Reliability Council (NERC).

The regional councils and the national council are industry organizations; they are not agencies of the Federal, State or local governments. All operations of the councils are financed by assessments on the utility members.

Annually on April 1 each regional council provides a report to the Department of Energy summarizing the coordinated plans and forecasts of the regional utilities for a ten-year period into the future with additional load and capacity forecasts for a second ten-year period. The structure of the report, arrived at by consultation between representatives of the councils, the former Federal Power Commission, and more recently the Department of Energy is shown in the Manual following.

A copy of a letter to the President of NERC, requesting that the councils furnish information on cogeneration, is attached, following the ERA-411 Manual.

A detailed review of the history, structure and functions of the reliability councils is provided in Appendix A of the DOE report "Electric Power Supply and Demand 1979-1988 for the Contiguous United States", published December 1979.

Approved by OMB
1903-0062
Expires 8-30-83

PROCEDURES MANUAL FOR COMPLETING THE COORDINATED REGIONAL BULK POWER SUPPLY PROGRAM REPORT

This report, which continues the annual series of reports initiated in 1970 under FPC Order 383-2, is voluntary under the Federal Power Act and P.L. 95-91, Department of Energy Organization Act.

The information collected by this report is not regarded as confidential and will not be treated as such.

ERA-411 (9-80)

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PROCEDURES MANUAL FOR COMPLETING THE COORDINATED REGIONAL BULK POWER SUPPLY PROGRAM REPORT

GENERAL INFORMATION

I. Purpose of Report	The ERA-411 provides the Economic Regulatory Administration (ERA) with a readily available, single, unified, comprehensive source of information outlining the regional planning of electric utilities for a 20-year advance period. Since utility system construction requires long lead times, extending to over 10 years for nuclear power plants, the long-range information to be provided is needed for purposes of governmental policy-making.
II. Who Submits	Each of the nine Regional Electric Reliability Councils of the National Electric Reliability Council submits an ERA-411 Report.
III. Reporting Schedule	The report is filed annually on April 1.
IV. Where the Report is filed	Each Council is to file six copies of its ERA-411 Report with the Director, Division of Power Supply and Reliability, Economic Regulatory Administration, U.S. Department of Energy, Washington, D.C. 20461, and two copies with each of the Division's five Field Offices. For the Field Office addresses see Appendix 2. Each Council is to file two copies of its ERA-411 Report with the Public Service Commission of each State which is wholly or partly within the geographic boundaries of the Council and two copies with the Director, Office of Electric Power Regulation, Federal Energy Regulatory Commission, Washington, D.C., 20426.
V. Further Information	Questions concerning the ERA-411 Report are to be directed to Richard Weiner, Director, Division of Power Supply and Reliability, Economic Regulatory Administration, 2000 M St., N.W. Washington, D.C. 20461, (202) 653-3899 or William Graban, Chief, Power Supply Planning Branch, Economic Regulatory Administration, 2000 M Street, N.W., Washington, D. C. 20461, (202)653-3828.

GENERAL INSTRUCTIONS

I. This manual is to be used as a guide for completing the ERA-411 report. The general organization, including formats, item numbers and titles, presented here should be followed. The page numbers of of the formats in these instructions are only intended for reference. Each Council may use the page numbering scheme it has used previously, in its report.

II. Include information from all Council members, and significant interconnected non-members within the service territory that have responded to data requests. All utilities for whom data is included are to be identified as shown on page 4. Data is to be grouped by Reporting Parties as defined in Appendix 1.

III. If information is entered in Item 8, (Additional Clarification Information) for a particular item, cross reference that item to the information entered in Item 8. For example, if clarification data on Item 7A is entered in Item 8, a reference to the data entered in Item 8 should be included in Item 7A.

DEFINITIONS

1. Net dependable capability (Net Capability)

The maximum load which a generating unit, power plant or system can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress. When used in reference to a system or plant, capability includes all generating units except those whose sole function is to supply emergency power for start-up and shut-down and is known as "installed capability". It includes the capability of units that may be temporarily inoperable because of maintenance, forced outage or other reasons, or only operable at less than full output. It excludes power required for plant operation.

Summer net dependable planned capability refers to the capability during the summer peak period. It is expected that the unit, plant or system will be able to supply the stated power output as needed during the peak period.

Winter net dependable planned capability refers to the capability during the winter peak period. It is expected that the unit, plant or system will be able to supply the stated power output as needed during the peak period.

2. Inoperable capability

The capability of generating units which cannot be operated for the period specified because of being in de-activated shut-down status, lack of personnel, lack of fuel or similar reasons. This category does not include units on forced outage or maintenance.

3. Peak hour demand (Peak load)

The largest demand (on the same basis as the net energy in definition 5) occurring within a specified period. It is intended that this be the 60-minute integrated demand. If a different time interval is used, the reporting party shall convert its data to the equivalent of 60-minute demand and shall state the actual demand interval. Report Peak Hour Demand on the same basis as Net Energy.

If the reporting party consists of more than one system, state whether the demand is coincident or non-coincident. If the demand reported is coincident, state in Item 8 how it was obtained.

4. Interruptible demand

Load which is interruptible by previous contractual agreement with a customer, under conditions specified in the contract.

5. Net Energy

The electric energy requirements of a system. It is defined as system net generation plus energy received from others less energy delivered to others. It includes system losses but excludes energy required for "pumping up" pumped storage plants.

6. Reporting year

The calendar year in which the report is filed. For instance, 1981 is the Reporting Year for a report filed April 1, 1981.

7. Previous year

The calendar year immediately preceding the reporting year. For a report filed April 1, 1980, the previous year is 1979.

8. Summer peak period

For the purposes of this report the summer peak period begins on June 1 and runs through September 30.

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9. **Winter peak period**

For the purposes of this report the winter peak period begins on December 1 and runs through March 31 of the following year. For instance, winter 1980 begins December 1, 1980 and runs through March 31, 1981. It is convenient to describe the winter peak period by means of two years. Thus the winter referred to here would be Winter 1980-81.

SPECIFIC INSTRUCTIONS

Cover Page - Enter on the cover page the name of the Council and the filing date of the report.

Introduction

Provide a brief executive summary to "highlight" each significant change from the previous filing. Significant changes would include changes of 1% or more in annual load and energy forecasts; cancellation or addition of large generating units or important transmission lines; establishment of new power pools and large-scale power transfer agreements or cancellation of existing such agreements.

Identification of reporting utilities

The report for the reliability council is to include information from significant interconnected non-members within its service territory that have responded to data requests. All utilities for whom data is included are to be identified as shown below, on a page preceding Item 1, by a 4-character alphabetic code created by the Council.

IDENTIFICATION OF REPORTING UTILITIES

Reporting Code	Utility System Name

ITEM 1

ESTIMATED ENERGY AND PEAK DEMAND FOR THE FIRST 10 YEARS AND ACTUAL DATA FOR THE PREVIOUS YEAR

In this item report actual energy and peak demand month by month for the previous year and estimated energy and peak demand month by month for the reporting year and the following year. Report annual energy and seasonal peak demand for the previous year, the reporting year and for each of nine additional years.

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This item is to be reported in total for each of the nine Reliability Councils of the National Electric Reliability Council. Appropriate groups of systems within a Council (Reporting Party) that plan the bulk power system on a coordinated basis may also report. Thus, some data may be reported more than once. It is recognized that a Council may not be completely divided into Reporting Parties, but to the extent that Reporting Parties exist they should report. It is recognized that, because of non-coincident peaks, some of the demand data may not be readily summable. State whether the demand reported is coincident or non-coincident.

Net Energy is the energy required from all power sources during the reporting period to satisfy the energy requirements of customers and includes transmission system losses. This data is reported in Gigawatthours. It includes the net energy from installed power sources and energy supplied by other sources such as interconnected utility systems and industrial sources. Special attention must be given to the handling of energy sales for resale to avoid duplicate reporting with other systems. Net Energy does not include energy required for pumping of pumped storage generating plants.

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COUNCIL ____________________

REPORTING PARTY ______________

ITEM 1

ESTIMATED ENERGY AND PEAK DEMAND FOR THE FIRST 10 YEARS AND ACTUAL DATA FOR PREVIOUS YEAR

19__ (Previous Year)	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
01 Peak Hour Demand-MW*												
02 Net Energy Gwh												
19__ (Reporting Year)												
03 Peak Hour Demand-MW*												
04 Net Energy Gwh												
19__ (Next Year)												
05 Peak Hour Demand-MW*												
06 Net Energy Gwh												

Actual Previous Year and 10 Year Projection	19__	19__	19__	19__	19__	19__	19__	19__	19__	19__	19__
07 Peak Hour Demand-MW* Summer											
08 Peak Hour Demand-MW* Winter											
09 Net Annual Energy-Gwh											

* Non-coincident unless otherwise stated.

ITEM 2-A

EXISTING GENERATING CAPABILITY

In this item, report all existing capability that is available at the beginning of the reporting calendar year. For hydro units, state the basis of the reported capability (adverse hydro, average hydro or other).

This data shall be reported only once for each Council. Existing generating capability data for the Reporting Parties should be segregated using the appropriate entry in Col 01.

All generating units are to be listed by utility. Joint ownership units may be shown in either of two ways. Identify the method used for each joint ownership unit. Only one method is to be used in a Council report and all owners of a jointly owned plant must use the same method.

Method A:	Each owner reports his share as net dependable capability in Columns 05 and 06 and cross references the other shares in a footnote but does not include the other shares in his capability.
Method B:	The utility operating the plant reports the full capability in Columns 05 and 06 and lists all shares in a footnote. Shares are also accounted for where appropriate as scheduled imports and exports in Item 2-C.

To facilitate reporting, the following abbreviations are to be used:

Column 01:	Identify each utility by the 4 character letter code listed under Identification (see p.4).
Column 03:	Report the location of each generating station, using the National Bureau of Standards Federal Information Processing Standards Publication (FIPS Pub 6-3, December 15, 1979) state (two digit) and county (three digit) codes. The publication may be obtained from:

National Technical Information
Service (NTIS)
U.S. Department of Commerce
Springfield, Virginia 22161
Telephone: (703) 557-4650

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Column 04: Identify the type of unit using the following codes:

ST	Steam Turbine-non nuclear
NB	Steam-BWR Nuclear
NP	Steam-PWR Nuclear
NH	Steam-HTGR Nuclear
IC	Internal Combustion
GT	Combustion Turbine (Gas Turbine)
HY	Conventional Hydro
PS	Pumped Storage Hydro
CW	Combined Cycle-Steam Portion-Waste Heat Only
CA	Combined Cycle-Steam Portion-Auxiliary Fired
CT	Combined Cycle-Combustion Turbine Portion
JE	Jet Engine
FC	Fuel Cell
SO	Solar
WM	Wind Power
GE	Geothermal
ZZ	None of the Above (Describe in Footnote)
UN	Unknown at this time

Columns 07 and 09: Identify the type of fuel using the following codes:

WH	Waste Heat
COL	Coal (general)
BIT	Bituminous Coal
SUB	Sub-Bituminous Coal
ANT	Anthracite Coal
LIG	Lignite Coal
PC	Petroleum Coke
LNG	Liquefied Natural Gas
MTH	Methanol
GAS	Gas (general)
NG	Natural Gas
RG	Refinery Gas
BFG	Blast Furnace Gas
COG	Coke Oven Gas
GST	Geothermal Steam
MUL	Multi-Fueled
REF	Refuse (solid waste)
OIL	Oil (general)
FO1	No. 1 Fuel Oil
FO2	No. 2 Fuel Oil
FO4	No. 4 Fuel Oil
FO5	No. 5 Fuel Oil
FO6	No. 6 Fuel Oil
UN	Unknown at this time

CRU	Crude Oil
TOP	Top Crude Oil
JF	Jet Fuel
KER	Kerosene
LPG	Liquid Propane Gas
RRO	Re-Refined Motor Oil
SNG	Synthetic Natural Gas
UR	Uranium
PL	Plutonium
WAT	Water
SUN	Sun
WND	Wind
TH	Thorium
WD	Wood and Wood Waste
ZZ	Fuel brought to the plant site that is converted before the combustion process, such as for a coal gasification system, is to be identified as type ZZ and explained in a footnote. Also use ZZ and a footnote for any type of fuel not listed above.

Columns 08 & 10: Identify the principal methods of transporting fuel to the plant site using the following codes:

WA	Water Transportation
TK	Truck
RR	Railroad
PL	Pipeline
CV	Conveyor

Column 11: State the number of days that the unit could operate on the alternate fuel only, at normal loads, before shutdown would be necessary because of operating problems such as boiler fouling, etc. Leave blank if use of alternate fuel is limited only by storage or availability

ITEM 2-B

FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES & REMOVALS

In this item, report all generating capability installations, removals, and equipment upratings and deratings projected for the 10 year period after the beginning of the reporting calendar year. For hydro units state the basis of the reported capability (adverse hydro, average hydro or other).

This data shall be listed in a single composite table for the Council, or for each Reporting Party identified in this report. The capability changes shall be grouped according to the calendar year in which they are projected to occur.

Use the same method of reporting joint ownership as in Item 2-A.

To facilitate reporting, the following abbreviations are to be used:

Column 01: Identify each utility by the same 4 character letter code used in Item 2-A.

Column 03: To give the location of each generating station, use FIPS state and county codes as in Item 2-A.

Column 04: Identify the type of unit using the same code as in Item 2-A.

Columns 07 & 09 : Identify the type of fuel using the same codes as in Item 2-A.

Columns 08 & 10 : Identify principal methods of transporting fuel to the plant site using the same codes as in Item 2-A.

Column 11: Show the month or season and year that the unit is projected to be included, removed, or rerated as a normal operating resource.

Column 12: Indicate footnotes as necessary.

Column 13: Show the status of projected changes as follows:

P Planned for installation but not utility-authorized.

L Regulatory approval pending. Not under construction.

T Regulatory approval received but not under construction.
U Under construction, less than approximately 50% completed.
A Generating unit capability increased (rerated or relicensed).
D Generating unit capability decreased (rerated or relicensed).
M Generating unit in deactivated shutdown status.
S Generating unit returned to service from deactivated shutdown status.
R Generating unit permanently removed from any service.
V Under construction, more than approximately 50% completed.

ITEM 2-C

SCHEDULED CAPACITY TRANSFERS

Each Council or Reporting Party is to report individually all scheduled imports and exports that involve electric systems outside of the Council or Reporting Party for the 10 year period after the beginning of the reporting calendar year. Transfers are to be reported only when all parties can be identified. Additional transfers which are not shown may be scheduled to accommodate a change in conditions or requirements. Some data may be repeated because this item is also to be reported by each of the Reporting Parties responding in Item 1.

Some data may be non-coincident. An example would be a transfer that changes magnitude, reported in July for an exporting utility whose peak load occurs in July and reported in August by an importing utility whose peak load occurs in August.

A Scheduled Import is a capacity transfer into a Reporting Party or Council at the time of the importer's peak load that is now (at the time the data is prepared) or is expected to be under contract or agreement for the period specified.

A Scheduled Export is a capacity transfer out of a Reporting Party or Council at the time of the exporter's peak load that is now (at the time the data is prepared) or is expected to be under contract or agreement for the period specified.

Transfers such as economy, maintenance, general purpose, non-displacement or emergency are not to be reported in this item.

COUNCIL____________________

REPORTING PARTY________________

ITEM 2-A

EXISTING GENERATING CAPABILITY
(at the beginning of the reporting calendar year)

				Primary Fuel				Alternate Fuel			
			Unit	Net Capability-MW		Fuel	Transp.	Fuel	Transp.	Days	
System 01	Station Name and Unit No. 02	Loc. 03	Type 04	Summer 05	Winter 06	Type 07	Method 08	Type 09	Method 10	Use 11	Notes 12

Council ____________________

Reporting Party ____________________

ITEM 2-B

FUTURE GENERATING CAPABILITY INSTALLATIONS, CHANGES AND REMOVALS
(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

				Net Capability-MW		Primary Fuel		Alternate Fuel				
System 01	Station Name and Unit No. 02	Loc. 03	Unit Type 04	Summer 05	Winter 06	Fuel Type 07	Transp. Method 08	Fuel Type 09	Transp. Method 10	Effective Date 11	Notes 12	Status 13

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Council________________________

Reporting Party__________________

ITEM 2-C

SCHEDULED CAPACITY TRANSFERS DURING THE TEN-YEAR PERIOD

SCHEDULED IMPORTS

ALL DATA IN MEGAWATTS

Other Party or Region	19		19		19		19		19		19		19		19		19		19	
	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.
TOTAL																				

SCHEDULED EXPORTS

Other Party or Region	19		19		19		19		19		19		19		19		19		19	
	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.
TOTAL																				

ITEM 3-A

PROJECTED RESOURCES, PEAK DEMANDS AND MARGINS FOR THE FIRST TEN YEARS

In this item, each Council is to report Resources, Peak Demand and Margin for summer and winter seasons for the 10 year period after the beginning of the reporting calendar year. Some of the information may be repeated because these data may also be reported by all Reporting Parties responding in Item 1. Peak demands reported here should agree with the corresponding entries in Item 1.

For hydro capability, report in Item 8 whether the data are for an adverse water year or average water year or other.

The information in Item 3-A is to be reported as follows:

Line 01: (Net Dependable Capability) as derived from the information in Items 2-A and 2-B. If this item differs from the simple summation of data in Items 2-A and 2-B, explain in Item 8.

Line 02: (All Scheduled Imports) is derived from the information in Item 2-C.

Line 03: (All Scheduled Exports) is derived from the information in Item 2-C.

Line 04: (Total Resources) is the sum of Lines 01 and 02, less Line 03.

Line 05: (Inoperable Capability) is total generating capability out of service in deactivated shutdown status, that could not be operated for the period specified, for reasons such as lack of manpower or fuel. This category is not to include forced or scheduled outages.

Line 06: (Operable Resources) is Line 04 less Line 05.

Line 07: (Peak Hour Demand) Transcribe from Item 1.

Line 08: (Interruptible Demand) is the interruptible demand included in Line 07, where appropriate contracts exist.

Line 09: (Demand Requirements) is Line 07 less Line 08.

Line 10: (Margin in Megawatts) is Line 06 less Line 09.

Line 11: (Scheduled Outage) is the capability expected to be unavailable because of maintenance. This item is to be reported only for the first five years of the ten year period.

Line 12: (Adjusted Margin) is Line 10 less Line 11, reported only for the first five years of the ten year period.

ITEM 3-B

ASSESSMENT OF ADEQUACY OF ADJUSTED MARGINS OF ITEM 3-A LINE 12

State the criteria now being used to determine reserve requirements, and provide an assessment of the adequacy of the adjusted margin shown on Line 12 of Item 3-A for providing reliable electric service. This assessment is to apply only to the first five years of the 10 years covered on Item 3-A. The assessment may be in whatever form deemed necessary because of such factors as geographic constraints, specific contractual arrangements, load densities and other characteristics which are unique to a Council or Reporting Party.

ITEM 4

ESTIMATED PEAK DEMANDS & RESOURCES FOR THE 11 TO 20 YEAR PERIOD

In this item, each Council is to report for each year of the 11 to 20 year period the estimated annual peak demands and the total resources which appear necessary to serve that demand. State the approximate total capacity to be added in this period and its components in terms of the estimated percentages of hydro, nuclear, fossil-fueled and other capability to be added. These data are also to be reported for each Reporting Party if the information is readily available on a Reporting Party basis.

COUNCIL______________________

REPORTING PARTY______________

ITEM 3-A

ESTIMATED PEAK RESOURCES, DEMANDS, & MARGINS FOR THE 10 YEAR PERIOD

	19		19		19		19		19	
	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.
RESOURCES IN MW										
01 Net Dependable Capability										
02 All Scheduled Imports										
03 All Scheduled Exports										
04 Total Resources (01+02-03)										
05 Incoperable Capability										
06 Operable Resources (04-05)										
DEMAND IN MW										
07 Peak Hour Demand										
08 Interruptible Demand										
09 Demand Requirements (07-08)										
MARGIN IN MW										
10 Margin (06-09)										
11 Scheduled Outage										
12 Adjusted Margin (10-11)										

	19		19		19		19		19	
	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.
RESOURCES IN MW										
01 Net Dependable Capability										
02 All Scheduled Imports										
03 All Scheduled Exports										
04 Total Resources (01+02-03)										
05 Inoperable Capability										
06 Operable Resources (04-05)										
DEMAND IN MW										
07 Peak Hour Demand										
08 Interruptible Demand										
09 Demand Requirements (07-08)										
MARGIN IN MW										
10 Margin (06-09)										

COUNCIL____________________

REPORTING PARTY_______________

ITEM 4

ESTIMATED PEAK DEMANDS & RESOURCES FOR THE 11 TO 20 YEAR PERIOD - MW

	Peak Hour Demand 01	Resources To Serve Demand 02
19___		
19___		
19___		
19___		
19___		
19___		
19___		
19___		
19___		
19___		

STATEMENT OF PROJECTED CAPABILITY ADDITIONS DURING THIS PERIOD

	Hydro	Nuclear	Fossil	Unknown or Other	Total
Percent					100

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ITEM 5-A

BULK POWER TRANSMISSION SYSTEM MAPS

Each Council is to submit a map or maps showing the existing bulk power transmission system, including ties to other Councils, and the bulk power system additions for a 10 year period beginning with the reporting year. As an option, each Reporting Party may submit individual system maps.

Only major geographic features and state boundaries, bulk power facilities and the names of major metropolitan areas need be shown. The map scale used is left to the discretion of the Region or Reporting Party. However, a 1:1,584,000 (25 miles to the inch) scale would be the most convenient. Show the voltage level of all bulk power transmission lines and the year of installation of all system additions.

The map requirement may be satisfied by either:

a.) A single map showing the existing bulk power transmission system as of January 1 of the reporting year and system additions for a ten-year period beginning with the reporting year or:

b.) A map showing the existing transmission system as of January 1 of the reporting year and all facilities added during that year and 4 additional years, plus another map (or maps) showing the existing transmission system as of January 1 of the 6th year and system additions for the remainder of the 10-year period. This option is recommended for use where the additions are numerous.

ITEM 5-B

LIST OF PROPOSED BULK POWER LINES

List the bulk power transmission lines significant for interconnected operation scheduled to be installed during the first ten years of this reporting period, with a brief summary of the reasons for construction.

To facilitate reporting, use the following instructions:

Column 01: Identify the line owners, using the four character letter codes of page 4.

Column 02: Identify each terminal of the facility.

Column 03: Show the line length in miles.

Column 04: Show the month and year that the facility is expected to be in service.

Column 05: List the nominal operating voltage in kilovolts.

Column 06: List the nominal design voltage in kilovolts.

Column 07: List any appropriate notes and the principal reasons for construction of the facility, being as brief as possible. Utilize simple phrases such as:

Relieve overloads
Provide area protection
Increase interchange capability
Deliver generator output
Stability considerations
Regulatory requirement (specify).

This list of reasons is not intended to be complete or restrictive but only to provide a few examples.

ITEM 5-C

LIST OF ALL FUTURE CRITICAL BULK POWER TRANSMISSION FACILITIES THAT WILL NOT BE IN SERVICE WHEN REQUIRED

In this item, identify all future critical bulk power transmission facilities that are now delayed and will not be in service as originally projected, with a concise narrative discussion of the reasons for the delay and a statement of the effect of the delay on reliability.

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The narrative discussion should include information on line ownership, planned operating and design voltage, required and expected service dates, and causes of delay such as adverse weather, material shortages, inadequate financing, regulatory hearings or pending litigation.

Transmission delays which are attributed to decreased load growth or the delay of associated generating units need not be reported.

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COUNCIL____________________________

REPORTING PARTY_______________________

ITEM 5-B

LIST OF PROPOSED BULK POWER LINES

Line Ownership 01	Terminals 02	Line Length miles 03	Expected Service Date 04	Nominal Voltage in KV		Notes 07
				Oper. 05	Design 06	

ITEM 6-A

NEAR TERM PEAK LOAD FLOW STUDIES

Each Council is to submit a load flow plot of its bulk power transmission network for the current summer peak load period and the following winter peak load period. If such plots are not available at the time that this report is filed, similar material covering the most recent summer and winter peak load periods is acceptable.

Each Council is to submit a narrative description of the adequacy of the bulk power transmission system facilities. This discussion should include a statement of the bulk power transfer capabilities in adjacent Councils. Significant limitations and the resulting special operating procedures applicable to the existing network should be described.

As an option, each Reporting Party identified in Item 1 of this report may submit load flow plots and narrative description of adequacy of facilities. If the Council is subdivided into Reporting Parties, transfer capability between Reporting Parties should be stated where applicable. There should be clear statements as to what transfer capability exists above that needed to fulfill contractual obligations.

ITEM 6-B

LIGHT LOAD SYSTEM ANALYSIS

Each Council is to submit a list of power flow studies for representative light load conditions, that have been made or will be made on a Council, Electric Region or Control Area basis. The studies should encompass the largest possible system that can be appropriately evaluated with respect to bus voltages, line loading and stability. The list should include studies completed, in progress or planned. The column headings of the format for Item 6-B are to be interpreted as follows:

Col 02	The date on which the study was made. This is intended to be the date on which all input data for the study were considered complete.
Col 03 -	The year and season which the study is intended to represent for analysis purposes.

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Col 06 - Total system load in MW, net of imports and exports.

Col 07 - Total system load as a percentage of the annual peak load for the year simulated. Indicate by (s) or (w) whether system peak occurs in summer or winter.

Col 08 - Provide information as to generating unit dispatch in brief summary form only.

Col 09 - Provide brief summary of results obtained from analysis of the study, such as vulnerability to instability; availability of additional power for export; voltage levels and phase angles; problems in var generation; or other items considered important.

ITEM 6-C

CONCEPTUAL LONG RANGE TRANSMISSION PLANS

Each Council is to provide a brief narrative discussion of basic changes in the bulk power system that might be made in the 11 to 20 year period of this report, indicating any possible increases in transmission voltage levels, use of direct current, or the use of other technology. As an option, each Reporting Party may submit a narrative description.

ITEM 6-D

SYSTEM EVALUATION CRITERIA

Each Council is to provide the network evaluation and system dynamic performance criteria as used in the appraisal reported in Items 6-A and 6-B, and discuss significant changes from the previous filing. As an option, each Reporting Party may submit criteria If this option is exercised, all applicable criteria are to be provided.

COUNCIL ______________________

REPORTING PARTY ____________

ITEM 6 - B

LIGHT LOAD SYSTEM ANALYSIS

					DESCRIPTION OF CONDITIONS			
STUDY NO.	DATE OF STUDY*	YEAR AND SEASON FOR SIMULATED CONDITION STUDIED	EXPORTS MW	IMPORTS MW	NET LOAD MW	NET LOAD % OF PEAK	GENERATION DISPATCH	SIGNIFICANT RESULTS
01	02	03	04	05	06	07	08	09

*The date on which all data were considered complete.

ITEM 7-A

COORDINATION OF OPERATIONS

Each Council is to provide a brief narrative summary of operating policies and practices intended to assure the integrity and reliability of the bulk power supply system. This summary should include at least the following items:

(a) Operating reserve policy

(b) Provisions for sustaining the operation of generating units on local loads.

(c) Procedures for coordination of maintenance outages of generation and transmission facilities.

(d) Procedures for selection, setting and maintenance of relays that affect the overall reliability of the interconnected network.

As an option, each Reporting Party may submit this information.

Each Council is to provide a brief explanation of how coordination is provided among the area control centers during normal and emergency conditions. Any plans to make significant changes in the functions of area control centers or regional coordination centers should be discussed. As a descriptive aid, maps or diagrams showing communication links should be included, and may be supplemented by a list of major control center facilities. For each area control center, show the FIPS state and county code, a list of the systems involved using the four character letter codes of page 4, and a list of other regions with which area control centers normally maintain contact.

ITEM 7-B

LOAD PRESERVATION PROGRAM

Each Region is to provide a statement of the estimated megawatt relief at the time of the annual peak load for each of the following load preservation steps. As an option, each Reporting Party may submit this information.

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The procedures are listed in the order shown below for consistency of reporting. The order is not intended to indicate a preferred sequence of implementation.

Line 01: Show the amount of non-essential internal utility system load such as office lighting, office air conditioning, system auxiliary power, etc. that can be curtailed.

Line 02: Show the expected load relief that can be expected for a four hour period for any voltage reduction levels used by the Region in emergency.

Line 03: Show the load that can be interrupted by automatic under-frequency relay operation if the system frequency were to drop to the stated relay settings.

Line 04: Describe any other procedures not indicated above and indicate the expected level of load relief. Include procedures that are used to arrest declining system frequency before operation of the automatic under-frequency relays and give an estimate of the time required for these procedures to become effective.

ITEM 7-C

CONTRACTUALLY INTERRUPTIBLE LOAD

State the total interruptible load supplied under contracts, for each Reporting Party. Show the lead time notice that the utility must provide to the customer and any other applicable conditions that must be met before the interruptibility option can be exercised.

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COUNCIL____________________

REPORTING PARTY_______________

ITEM 7-B

LOAD PRESERVATION PROGRAM

Option	Estimated MW Relief*
01 Curtailment of non-essential utility system load	______
02 Voltage reductions _______%	______
_______%	______
_______%	______
_______%	______
03 Operation of automatic underfrequency relays	______
_______Hz	______
_______Hz	______
_______Hz	______
_______Hz	______
04 Other load preservation procedures (except for interruptible load, which is reported in ITEM 7-C)	______

* Indicate whether the magnitude of relief is dependent on the magnitude of system load at the time the stated measures are implemented

COUNCIL____________________________

REPORTING PARTY________________________

ITEM 7-C

CONTRACTUALLY INTERRUPTIBLE LOAD
(At Time of Annual Peak)

Utility Code 01	Load That Can Be Interrupted (In MW) 02	Contractual Conditions (Describe as briefly as possible) 03

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ITEM 8

ADDITIONAL INFORMATION FOR CLARIFICATION

This item is provided so that each Reliability Council may submit information, in addition to that submitted in the preceding seven items of this report, that is deemed necessary for clarification or to present specific characteristics of the Council or Reporting Parties. For example, expected water impoundments for hydro-electric installations, data related to individual utility systems, or special operating arrangements may be included. Provide cross-reference to the appropriate other Items in this report where necessary.

APPENDIX 1 of
ERA-411 MANUAL

Appendix 1 of this Manual was a list of utilities whose data was usually included in the ERA-411 Report, grouped by Electric Regions. Because of some changes in the reporting by utilities for the April 1, 1981 ERA-411 Reports, Appendix 1 has been removed. The utilities for whom data is actually included in the ERA-411 Reports dated April 1, 1981 are listed in Appendix B.

Mailing Addresses

Field Offices
of
The Division of Power Supply and Reliability

Atlanta, Georgia
Mr. William Scott, Branch Chief
ERA Division of Power Supply
and Reliability
Room 528
1371 Peachtree St., N.E.
Atlanta, Georgia 30309

Chicago, Illinois
Mr. Herbert Rinder, Branch Chief
ERA Division of Power Supply
and Reliability
Room A332
175 West Jackson Blvd.
Chicago, Illinois 60604

Fort Worth, Texas
Mr. Johnny R. Johnson, Branch Chief
ERA Division of Power Supply
and Reliability
Room 9A05
819 Taylor Street
Fort Worth, Texas 76102

New York, New York
Mr. Gilbert Cigal, Branch Chief
ERA Division of Power Supply
and Reliability

26 Federal Plaza
New York, New York 10007

San Francisco, California
Mr. Robert Van Slambrook, Branch Chief
ERA Division of Power Supply
and Reliability
6th Floor
333 Market Street
San Francisco, California 94105

Department of Energy
Washington, D.C. 20461

OCT 28 [illegible]

Mr. Walter D. Brown
President
National Electric Reliability
 Council
Research Park, Terhune Road
Princeton, New Jersey 08540

Dear Walter:

Some of the individual Reliability Councils have indicated that they are considering ways in which cogeneration can be factored into the reliability analysis aspects of the Long Range Coordinated Planning Reports (ERA-411). This subject has engaged ERA attention also. An electric utility service area in which a significant amount of capacity will be provided by cogeneration will have to evaluate a new dimension in system planning. The level at which cogeneration becomes "significant" in relation to an electric system's own capacity is difficult to determine. Since there appears to be a variety of approaches to the incorporation of cogeneration into system planning and the analysis of reliability, it is best to proceed cautiously.

The preparation of the 1981 Councils' ERA-411 Reports will require some guidance to Reporting Parties. Those parties which feel it advisable to do so should discuss the effect of cogeneration on system reliability in Item 3B. The discussion could incorporate a table of the ten year resources with cogeneration data shown separately from total system data, in, possibly, terms of peak demands, capacity and energy. Other factors related to system reliability as affected by cogeneration will no doubt occur to planning and operating personnel. Item 8 would be a suitable place in which to discuss such factors. The present ERA intention is to encourage a full discussion of cogeneration as it affects utility planning, in the hope that the important aspects of any problems can be exposed at an early date.

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Possibly a consensus can be reached, as to a useful and consistent format for the evaluation and reporting of reliability as affected by cogeneration, by the time preparation of the 1982 ERA-411 Reports is begun. I would appreciate it if you would discuss this matter with the Reliability Councils and advise me of your findings.

Sincerely,

/s/ Richard E. Weiner

Richard E. Weiner
Director
Division of Power Supply
and Reliability
Economic Regulatory Administration

APPENDIX B

APPENDIX B

Utilities for which Data Is Included In The Report on Power Supply and Demand 1981 - 1990

Each of the nine Reliability Councils constitutes a Reporting Party. In addition, data within each Council is grouped by Reporting Parties as shown below. The utilities listed below are those for whom data is included in this report. Some of the utilities listed are not members of a Council, but have cooperated by furnishing data to be incorporated in the ERA-411 Report.

East Central Area Reliability Coordination Agreement (ECAR)

Electric Region	Utilities Whose Data Are Included
1. Allegheny Power System (APS)	Allegheny Power System
2. American Electric Power System (AEP)	American Electric Power Co. 1/ Buckeye Power, Inc. Richmond, Indiana (Municipal) Ohio Valley Electric Corp. 2/
13. Central Area Power Coordination Group (CAPCO)	Cleveland Elec. Illum. Co. City of Cleveland Toledo Edison Co. Ohio Edison Co. Pennsylvania Power Co. 3/ Duquesne Light Co. Bryan, Ohio (Municipal)
14. Cincinnati, Dayton Group (CD)	Cincinnati Gas and Electric Co. Hamilton, Ohio (Municipal) Dayton Power & Light Co.
15. Kentucky Group	Big Rivers Electric Cooperative East Kentucky Power Cooperative Henderson, Kentucky (Municipal) Kentucky Utilities Louisville Gas & Electric Co Owensboro, Ky (Municipal)
16. Indiana Group (All Indiana utilities except Indiana and Michigan Electric Co.)	Hoosier Energy Rural Electric Coop. Public Service Co. of Indiana Northern Indiana Pub. Serv. Co. Indianapolis Power & Light Co. Southern Indiana G. & E. Co. Wabash Valley Power Association

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1/ Including Columbus & Southern Ohio Electric Co.
2/ Including Indiana-Kentucky Electric Co.
3/ A subsidiary of Ohio Edison Co.

ECAR (Cont'd.)

Electric Region	Utilities Whose Data Are Included
18. Michigan Electric Coordinated	Consumers Power Co. Detroit Edison Co. Detroit, Mich. Public Ltg. Dept. (Municipal) Lansing, Mich. Bd. of Water and Light (Municipal) Edison Sault Electric Co. Mich. Municipal Coop Power Pool Conalco Grand Haven Bd. of Light & Power Lowell Light and Power Northern Michigan Electric Coop. Traverse City Light and Power Dept. Wolverine Electric Coop. Zeeland Bd. of Public Works

Electric Reliability Council of Texas (ERCOT)
Electric Region No. 23

Utilities Whose Data Are Included

Austin Electric Dept. (Municipal)
Brownsville, City of (Municipal)
Central Power and Light Co.
West Texas Utilities Co.

San Antonio Public Service Board

Houston Lighting & Power Co.

Lower Colorado River Authority

Texas Municipal Power Pool

- Brazos Electric Power Cooperative, Inc
- Bryan, City of (Municipal)
- Denton Municipal Utilities (Municipal)
- Garland, City of (Municipal)
- Greenville Electric Dept. (Municipal)

Texas Utilities Co. System
- Dallas Power & Light Co.
- Texas Electric Service Co.
- Texas Power and Light Co.

South Texas and Medina Electric Cooperative Pool

- Medina Electric Cooperative, Inc.
- South Texas Electric Cooperative, Inc.

Mid-Atlantic Area Council (MAAC)
Electric Region No. 5

	Utilities Whose Data Are Included

PJM	Atlantic City Electric Co.
	Baltimore Gas and Electric Co.
	Delmarva Power and Light Co.
	General Public Utilities Corp.
	  Jersey Central Power & Light Co.
	  Metropolitan Edison Co.
	  Pennsylvania Electric Co.
	Pennsylvania Power & Light Co.
	Philadelphia Electric Co.
	Potomac Electric Power Co.
	Public Service Electric and Gas Co.
	UGI Corp.

MAAC Associates	Allegheny Electric Cooperative The Easton, Md. Utilities Commission The City of Vineland, N.J. Electric Utility The City of Dover, Delaware Southern Maryland Electric Coop., Inc.

Mid-America Interpool Network (MAIN)

Electric Region	Utilities Whose Data Are Included
6. Commonwealth Edison Co. (CECo)	Commonwealth Edison Co. Rochelle, Ill. Municipal Utilities Village of Winnetka, Ill.
17. Illinois - Missouri Group (ILLMO)	Central Illinois Light Co. Central Illinois Pub. Serv. Co. Illinois Power Co. City Water, Light & Power Springfield, Illinois Southern Illinois Power Cooperative Union Electric Co. System 1/ Soyland Power Cooperative City of Columbia, Mo. Western Illinois Power Cooperative Electric Energy, Inc.
19. Wisconsin Upper Michigan System (WUMS)	Madison Gas & Electric Co. Wisconsin Electric Power Co. System Wisconsin Power & Light Co. Wisconsin Public Service Corp. Upper Peninsula Power Co. Kaukauna-Menasha Interconnected System (WISC) City of Manitowoc, Wisc. City of Marshfield, Wisc.

1/ Including Subsidiaries

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Mid-Continent Area Reliability Coordination Agreement (MARCA)

Electric Region No. 20

Utilities Whose Data Are Included

Basin Electric Power Cooperative
Cooperative Power Association
Dairyland Power Cooperative
Eastern Iowa Light & Power Cooperative
Interstate Power Co.
Heartland Consumers Power District
Iowa Electric Light & Power Company
  Central Iowa Power Cooperative
Iowa Power & Light Co.
Iowa Public Service Co.
  Corn Belt Power Cooperative
Iowa Southern Utilities Co.
Lake Superior District Power Co.
Lincoln Electric System
Minnesota Power & Light Co.
Minnesota Power Cooperative, Inc.
Missouri Basin Muni. Power Agency
Montana-Dakotas Utilities Co.
Muscatine Power & Water, Iowa
Nebraska Public Power District
Northern States Power Co.
Northwestern Public Service Co.
Northwest Iowa Power Coop.
Omaha Public Power District
United Power Association
Western Area Power Administration -
  Billings Area
Otter Tail Power Co.

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Northeast Power Coordinating Council (NPCC)

Electric Region	Utilities Whose Data Are Included
3. New England Power Pool (NEPOOL)	Bangor Hydro Electric Company
	Boston Edison Company
	Braintree Electric Light Dept., Mass.
	Burlington Electric Dept., Vt.
	Central Maine Power Company
	Central Vermont Public Service Co.
	Connecticut Yankee Atomic Power Co.
	Eastern Utilities Associates
	Fitchburg Gas & Electric Light Dept., Mass.
	Green Mountain Power Corporation
	Holyoke Gas & Electric Dept., Mass.
	Hudson Light & Power Dept., Mass
	Ipswich Municipal Light Dept., Mass.
	Maine Public Service Company
	Maine Yankee Atomic Power Company
	Marblehead Municipal Light Dept., Mass
	New England Electric System
	New England Gas & Electric Association
	Newport Electric Corporation, R.I.
	Northeast Utilities
	Norwalk Second Taxing District, Conn.
	Norwalk, Department of Public Utilities
	Peabody Municipal Light Dept., Mass.
	Public Service Service Company of New Hampshire
	Shrewsbury Electric Light Dept., Mass.
	Taunton Municipal Light Dept., Mass.
	United Illuminating Company
	Vermont Electric Power Company
	Vermont Yankee Nuclear Power Corporation
	Wallingford, Conn. Electric Dept. (Muni)
	Yankee Atomic Electric Company
4. New York Power Pool (NYPP)	Central Hudson G. & E. Corp.
	Consolidated Edison Co. of N.Y.
	Jamestown Municipal Electric System
	Long Island Lighting Co.
	New York State G.&E. Corp.
	Niagara Mohawk Power Corp.
	Orange & Rockland Utilities, Inc.
	Power Authority of the State of N.Y.
	Rochester G.&E. Corp.
	Village of Freeport, N.Y.

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Southeastern Electric Reliability Council (SERC)

Electric Region	Utilities Whose Data Are Included
7. Florida Coordinating Group (FCG)	City of Homestead City of Kissimmee City of Lakeland City of Tallahassee City of Vero Beach Florida Power & LIght Co Florida Power Corp. Fort Pierce Utilities Authority Gainesville/Alachua County Regional Utilities Board Jacksonville Electric Authority Lake Worth Utilities Authority New Smyrna Beach Utilities Commission Orlando Utilities Commission Sebring Utilities Commission Southeastern Power Administration Tampa Electric Co.
9. Southern Company Region (SoCo)	Alabama Electric Cooperative Alabama Power Company Crisp County Power Commission, Ga. Georgia Power Company Gulf Power Company Mississippi Power Company Savannah Electric & Power Company So. Mississippi Electric Power Assoc. Southeastern Power Administration
11. Tennessee Valley Authority Region (TVA)	Nantahala Power & Light Co. Tapoco, Inc. Tennessee Valley Authority
12. Virginia-Carolinas Region (VACAR)	Carolina Power and Light Co. Duke Power Co. South Carolina Electric & Gas Co. South Carolina Public Service Authority Southeastern Power Administration Virginia Electric & Power Co. Yadkin, Inc.

Southwest Power Pool (SPP)

Electric Region	Utilities Whose Data Are Included
8. Middle South/Gulf States Group 1/ 2/ Group	Arkansas Electric Cooperative Corp. Cajun Electric Power Cooperative, Inc. Central Louisiana Electric Company, Inc. City of Greenwood, Miss. City of Jonesboro, Ark. City of Lafayette, La. City of Ruston, La. Gulf State Utilities Company Middle South Utilities, Inc. Arkansas Power & Light Company Louisiana Power & Light Company Mississippi Power & Light Company New Orleans Public Service, Inc.
21. Missouri-Kansas Group (MOKAN)	Associated Electric Cooperative 3/Board of Public Utilities - Kansas City, Ka Central Kansas Power Company 3/Chanute, Ka., Muncipal Utilities City Power & Light - Independence, Mo. 3/City of Winfield, Ka. City Utilities, Springfield, Mo. 3/Coffeyville Municipal Water and Light Empire District Electric Company Kansas City Power & Light Company Kansas Gas and Electric Company Kansas Power & Light Company Missouri Public Service Company St. Joseph Light & Power Company Sunflower Electric Cooperative, Inc. Western Power Division - Central Telephone & Utilities

1/ This group combines the Regions designated previously as Region 8 and Region 10.

2/ Arkansas-Missouri Power Co., formerly listed separately in this group, is now included with Arkansas Power & Light Co. Missouri Utilities Co., formerly listed separately in this group, is now included with Union Electric Co. in the MAIN Report.

3/ These utilities have furnished data in previous years but did not furnish data for the April 1, 1981 ERA-411 Report.

SPP (Continued)

Electric Region	Utilities Whose Data Are Included
22. Oklahoma Group	Grand River Dam Authority
	Oklahoma Gas & Electric Company
	Public Service Company of Oklahoma
	Southwestern Electric Power Company
	Southwestern Power Administration
	Southwestern Public Service Company
	Western Farmers Electric Cooperative
	Ponca City, Oklahoma
	Lea County Electric Coop., Inc.
	New Mexico Electric Service Co.

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Western Systems Coordinating Council WSCC)

Electric Region	Utilities Whose Data Are Included
24. Rocky Mountain Power Area (RMPA)	Basin Electric Power Cooperative (Wyoming and South Dakota Rushmore G&T) Black Hills Power and Light Co. Colorado Springs, City of Colorado-Ute Electric Association Lamar, City of Platte River Power Authority Public Service Co. of Colorado So. Colorado Power Division, Central Telephone & Utilities Corp. Tri-State Generation & Transmission Association, Inc. WPRS - Lower Missouri Region WPRS - Upper Colorado Region Western Area Power Administration Denver Area Western Area Power Administration Salt Lake Area

Data for 105 smaller systems in Region 124 is included with the data for the systems listed above.

Electric Region	Utilities Whose Data Are Included
25. Northwest Power Pool	Pacific Power & Light Co. Portland General Electric Co. Puget Sound Power & Light Co. The Washington Water Power Co. Montana Power Co. Chelan County P.U.D. No. 1 Cowlitz County P.U.D. No. 1 Douglas County P.U.D. No. 1 Eugene Ore. Water & Electric Board Grant County P.U.D. Grays Harbor P.U.D. No. 1 Pend Oreille County P.U.D. Seattle City Light, Wash. Snohomish County P.U.D. City of St. George, Utah Tacoma City Light, Wash. U.S. Corps of Engineers (North Pacific Div.) Bonneville Power Administration City of Bountiful, Idaho Idaho Power Co. WPRS Pacific Northwest Region - BPA (So. Idaho System) WAPA Loads Wheeled by Utah Power and Light Co. (Upper Colo) Utah Power & Light Co.

Data for 162 smaller systems in Region 24 are included with the data listed above.

WSCC (Continued)

Electric Region	Utilities Whose Data Are Included
26. Arizona-New Mexico Group (A-NM)	Arizona Electric Power Cooperative Arizona Power Authority Arizona Public Service Company Citizens Utilities Company El Paso Electric Company Imperial Irrigation District Plains Electric G&T Cooperative Public Service Co. of New Mexico Salt River Project San Carlos Irrigation Project Southern California Edison Company (Blythe District) Tucson Electric Power Company WPRS - Lower Colorado Region (including WAPA Loads in UC Region) WPRS Rio Grande Project (SW Region) Western Area Power Administration Boulder City

Data for 28 smaller systems in Region 26 are included with the data for the systems listed above.

27. Southern California-Nevada Group (SC-N) 1/	Anaheim, City of Burbank, City of California Dept. of Water Resources CP National Corp. (Nevada System) Glendale, City of Lincoln County Power District Los Angeles Dept. of Water & Power, City of Metropolitan Water District/So. California Nevada Power Company Pasadena, City of Riverside, City of San Diego Gas & Electric Company Southern California Edison Company State of Nevada WPRS at Boulder City

NOTE: WPRS = Water and Power Resources Service of the Dept. of the Interior, formerly U.S. Bureau of Reclamation (USBR)

1/ Data for 36 smaller systems are included with the data reported by Region 27 and 28. WSCC does not specify which of these systems are in Region 27 and which are in Region 28.

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WSCC (Continued)

Electric Region	Utilities Whose Data Are Included
28. Northern California Nevada Group (NC-N) 2/	California Dept. of Water Resources Pacific Gas & Electric Company Sacramento Municipal Utility District San Francisco, City and County of Sierra Pacific Power Company Turlock Irrigation District Modesto Irrigation District WPRS - Mid Pacific Region Western Area Power Administration - Sacramento

Data for 28 smaller systems in Region 26 are included with the data for the systems listed above.

APPENDIX C

APPENDIX C

This Appendix is a reprint of a report published in May 1981, which reviews the projected power supply situation for Summer 1981.

In the detailed regional analyses prepared for the report, the possibility of capacity outages at the time of peak summer demand was considered. For each region, a table was incorporated in the report showing the possible reduction in capacity available at the time of peak demand because of scheduled maintenance, forced outages, or other reasons. Staff recognizes that the limited data sample used to compute the capacity unavailable did not permit statistically rigorous computation (e.g., projected outage rates for Electric Regions are based on historical outages at only the peak hour for each of the previous four years). Therefore, the projected "actual" reserve margins used in the report should be considered only as gross indicators of power supply adequacy.

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Staff Report
Estimated Electric Demand and Supply for Summer 1981 Contiguous United States

May 1981

U.S. Department of Energy
Assistant Secretary for
Environmental Protection, Safety and Emergency Preparedness
Division of Power Supply and Reliability
Washington, D.C. 20461

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Staff Report on Projected Summer 1981
Electric Load-Supply Situation

SUMMARY

This report summarizes the most recent data available concerning projected electrical peak demands and available power resources for the 1981 summer peak period, as reported by electric utilities in the contiguous United States. The data on loads, purchases and sales, and planned capability, grouped by Regional Council 1/ areas and by Electric Regions 1/ within the Council areas, were obtained from the Reliability Council ERA-411 reports dated April 1, 1981, filed with the Department of Energy. In some instances the data have been revised by staff of the Division of Power Supply and Reliability after discussions with the Councils.

No wide-spread large-scale reliability problems are foreseen for electric power supply this summer, on the basis of the supply and demand projections furnished by the Councils. In some Electric Regions reserve margins could drop to levels considered inadequate for reliable service, if historical generating unit outage levels recur. These regions are

Electric Region	
1	Allegheny Power System
6	Commonwealth Edison Co. Area 2/
12	VACAR
13	CAPCO Group
14	Cincinnati-Dayton Group
28	Northern California-Nevada Area

If projected demands occur and the possible large-scale outages of capacity take place, in these Regions, customers may experience unreliable service 3/ during the summer months. However, the reserves listed for these Regions must be viewed in the context of the capacity available within the corresponding Reliability Council area and the ability of the transmission network to make that capacity available where needed. Careful management of generating and transmission facilities by utility personnel engaged in system operation will be necessary if difficulties are to be minimized.

Data for Electric Regions 2 and 14 in the ECAR area reflect the incorporation of the Columbus and Southern Ohio Electric Co. System (CSO) into the American Electric Power System. CSO was formerly part of the Cincinnati-Columbus-Dayton (CCD) group, which is now designated Cincinnati-Dayton (CD).

Reserve Margins

Each of the Regional Electric Reliability Council areas, and each Electric Region (except 6,27,28), has a projected planned reserve margin that would be satisfactory under normal conditions (Table A). These margins, which do not reflect the effects of capacity purchases and sales transactions between Regions or between Council areas, scheduled maintenance, capacity known to be unavailable, and forced outages, range from 1.2% to 62.8% of the peak demands projected. Table A also shows the possible actual reserve at the time of peak demand, after allowance for scheduled purchases and sales and the capacity that may be unavailable for various reasons; the range is from a negative 15.8% to a positive 27.7%.

1/ See Map on p. iv

2/ The entire MAIN council area could have an actual reserve of 0.3% if historic large-scale capacity unavailability recurs.

3/ "Unreliable" is a qualitative term that includes conditions ranging from minor reductions in voltage for short periods to long-term major voltage reductions, frequency fluctuations, unplanned interruptions to service, and planned rotating interruptions.

Customer service reliability cannot be directly deduced from Council or Regional reserve margins, since much depends on the weather, daily and weekly variation in load, the interconnections among system, each individual utility's internal transmission, generation facilities and other factors. It is generally agreed, however, that reserve margins of the magnitude shown with an asterisk in Table A would be too low for consistently reliable service. For each of the Electric Regions marked with an asterisk, capacity purchases not now scheduled may be needed. Such capacity appears to be available, for each of these Regions, from systems within their Reliability Council area or from adjoining Council areas.

Table A shows reserves anticipated for the time of the peak non-coincidental demand of each Council area and Electric Region. The peak non-coincidental demand was obtained for each geographic area by summing the peaks projected for each utility in that area. The utility peaks may occur at different times, therefore the area peak tabulated may exceed (probably by no more than some 1 or 2 percent) the actual coincident peak demand. In the case of wide-spread extreme weather conditions, the coincident and non-coincident peaks in any one Council or Electric Region can be very nearly the same. The timing factor also affects the scheduled imports and exports (purchases and sales of capacity) included in the reserve calculations.

Estimates of generating capacity unavailable for service because of scheduled maintenance are as projected in the Reliability Council ERA-411 Reports in most instances. In some cases this capacity has been estimated by staff 1/ on the basis of historic data reported by electric utilities from January 1977 through December 1980. In all cases, the estimates of generating capacity on forced outage and "otherwise unavailable" have been provided by staff. These estimates are based on the outage data reported by electric utilities from January 1977 through December 1980. Generating capacity "otherwise unavailable" includes units that cannot be operated for lack of fuel or because of environmental restrictions; units derated because of cooling water temperature limitations, stack emission limitations, or low quality of fuel; units that cannot run at full capability because of partial forced outages; units whose full capacity cannot be utilized because of transmission limitations.

For the reasons stated, the tabulated data are to be regarded as estimates, not exact numbers that can be verified at a specified time. Following Table A there is detailed discussion of each Reliability Council and Electric Region.

1/ "Staff" in this report refers to the staff of the Division of Power Supply and Reliability.

[redacted]

Table A
Projected Electric Region Reserves
Summer 1981

Electric Region	Planned Reserve Percent	Possible Actual Reserve Percent 1/
ECAR		
1. APS	51.4	2.7 *
2. AEP	62.8	23.1
13. CAPCO	29.9	(2.2)*
14. CD	27.3	3.3
15. Kentucky	29.3	27.7
16. Indiana	27.4	11.6
18. MECS	31.6	6.7
Total ECAR	39.0	11.0
MAAC		
5. PJM	35.4	9.9
MAIN		
6. Commonwealth	9.6*	(15.8)*
17. ILLMO	21.5	12.4
19. WUMS	26.7	12.7
Total MAIN	17.5	0.3*
MARCA		
20. MAPP	38.0	28.0
NPCC		
3. NEPOOL	39.7	8.7
4. NYPP	44.2	16.2
Total NPCC	42.3	13.1
SERC		
7. Florida	32.0	12.4
9. Southern	32.6	17.9
11. TVA	43.5	14.4
12. VACAR	24.0	2.9*
Total SERC	32.1	11.0
SPP		
8. MSU/GULF	12.4	9.1
21. MOKAN	17.7	9.3
22. Oklahoma	34.2	19.1
	20.6	12.3
Total Interconnected Councils	32.2	11.2
WSCC		
24. RMPA	47.0	21.3
25. NWPP	45.9	12.1
26. Az-N.M.	49.6	23.6
27. So. Cal.-Nev.	3.9*	11.0
28. No. Cal.-Nev.	1.2*	1.3*
Total WSCC	25.7	11.5
ERCOT		
23. TIS	31.0	17.3

1/ After allowance for net scheduled purchases and sales, scheduled maintenance, forced outages or other unavailable capacity not controllable by the operating electric utility. Possible additional inter-regional capacity purchases and sales are not included.

* Undesireably low reserve.

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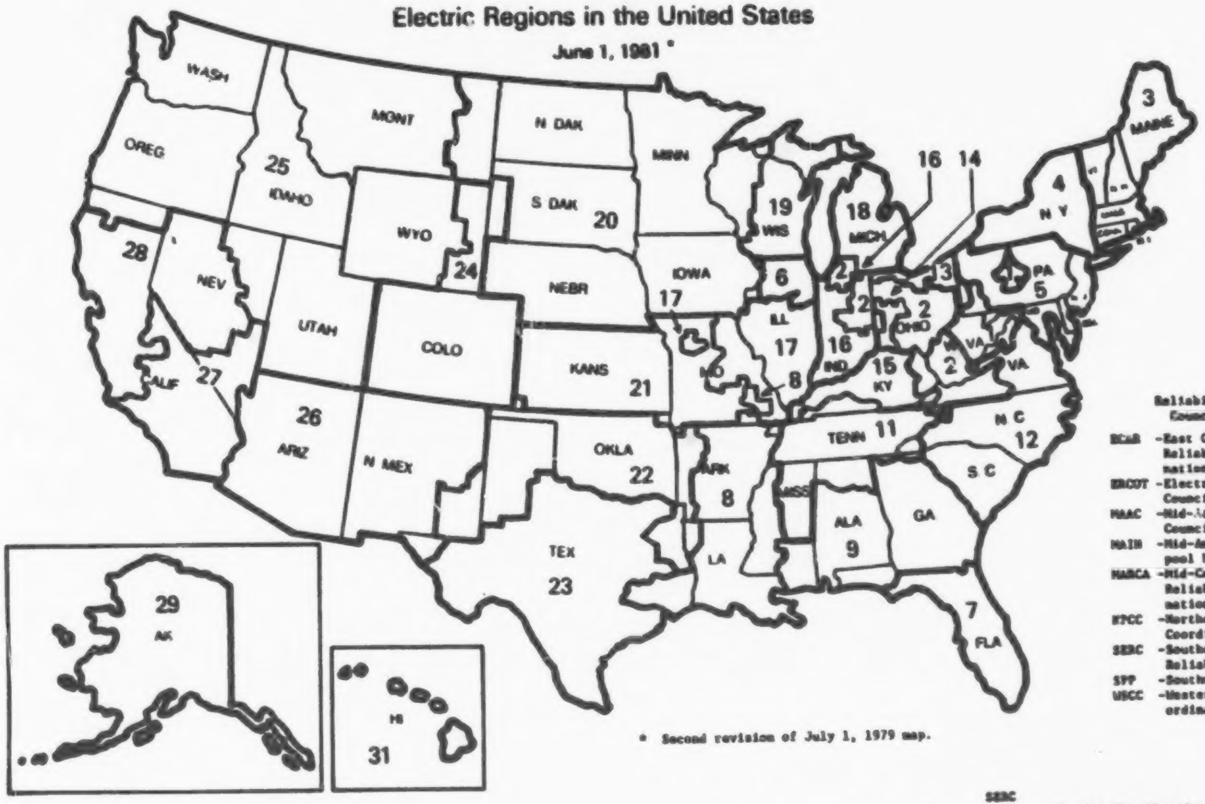
Department of Energy

Electric Regions in the United States

June 1, 1981 *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Reliability Council

ECAR -East Central Area Reliability Coordination Agreement
ERCOT -Electric Reliability Council of Texas
MAAC -Mid-Atlantic Area Council
MAIN -Mid-America Interpool Network
MARCA -Mid-Continent Area Reliability Coordination Agreement
NPCC -Northeast Power Coordinating Council
SERC -Southeastern Electric Reliability Council
SPP -Southwest Power Pool
WSCC -Western Systems Coordinating Council

* Second revision of July 1, 1979 map.

Electric Region		Identification
	ECAR	
1		Allegheny Power System (APS)
2		American Electric Power System (AEP)
13		Central Area Power Coordination Group (CAPCO)
14		Cincinnati, Dayton Group (CD)
15		Kentucky Group
16		Indiana Group - All Indiana Utilities except I&M Electric Co.
18		Michigan Electric Coordinated Systems (MECS)
	ERCOT	
23		Texas Interconnected Systems Group (TIS)
	MAAC	
5		Pennsylvania-New Jersey-Maryland Interconnection (PJM)
	MAIN	
6		Commonwealth Edison Co.
17		Illinois-Missouri Group (ILLMO)
19		Wisconsin-Upper Michigan Systems Group (WUMS)
	MARCA	
20		Mid-Continent Area Power Pool (MAPP)
	NPCC	
3		New England Power Pool (NEPOOL)
4		New York Power Pool (NYPP)
	SERC	
7		Florida Coordinating Group (FCG)
9		Southern Company Group
11		Tennessee Valley Authority Group (TVA)
12		Virginia-Carolinas Group (VACAR)
	SPP	
8+		Middle South Utilities/ Gulf States Utilities Group
21		Missouri-Kansas Group (MOKAN)
22		Oklahoma Group
	WSCC	
24		Rocky Mountain Power Pool (RMPP)
25+		Northwest Power Pool (NWPP)
26		Arizona-New Mexico Group
27		Southern California-Nevada Group
28		Northern California-Nevada Group

+Region 8 includes former Regions 8 and 10.
Region 25 includes former Regions 25 and 30.

1. EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT (ECAR)

The East Central Area Reliability Coordination Agreement (ECAR) consists of eighteen member systems in seven power pooling groups which serve all or parts of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland and Tennessee. In addition, the area covered by ECAR includes a number of small systems described as "Liaison Members" of ECAR.

The ECAR noncoincident peak load forecast for the 1981 summer season is 64,346 megawatts (see Table 1.1), a 1.7 percent increase over the actual peak of the 1980 summer. The small increase in load projected for this summer probably reflects the depressed economy of the region, conservation effects and summer weather less extreme than experienced in 1980.

ECAR as a whole is a winter peaking area, although many of its members peak in the summer (usually, each subsequent summer peak exceeds the preceding winter peak and the next winter peak exceeds the preceding summer peak). The diversity allows systems within ECAR to take advantage of seasonal diversity in scheduling maintenance, capacity transfers and in establishing reserve criteria.

Planned capability to meet the 1981 summer peak load forecast is 89,435 megawatts. Included in this total is 500 MW of new coal-fired capacity scheduled for August 1981. 1/ Of the planned generating capability, more than 80 percent is coal-fired, utilizing coal produced primarily within the region from the Appalachian coal fields. Nuclear generating capacity is about 5 percent of installed capability.

The projected actual 1981 summer reserve margins for each ECAR region are given in Table 1.1. The values for scheduled maintenance, full forced outages and other unavailable capability shown in the table were calculated using the historical percent average outages of installed capacity at the time of the seasonal peaks for the period 1977-1980 applied to Line 1 of Table 1.1. 2/ As shown on Table 1.1 for the 1981 summer period, the ECAR region should have adequate reserves (7,092 MW or 11.0 percent) to meet its load responsibility. The reserve margins for individual Electric Regions vary from negative 2.2 percent (CAPCO) to 22.7 percent (Kentucky Group). In each Region except CAPCO the projected reserve margin appears adequate to cover unforeseen contingencies. However, there is enough extra capability within ECAR to supply CAPCO's needs. In addition, the transmission system is adequate to provide energy and capacity transfers among the Regions if unusual problems arise.

The Electric Regions in ECAR are:

1. American Electric Power Group (AEP)
2. Allegheny Electric Power System (APS)
13. Central Area Coordination Group (CAPCO)
14. Cincinnati-Dayton Group (CD)
15. Indiana Group
16. Kentucky Group
18. Michigan Electric Coordinated System (MECS)

1/ See p. 1.3 for a discussion of the effect of this unit.

2/ See Tables 1A.4, 1B.4, 1C.4, 1D.4. These tables are based on utility reports filed on FPC Form 12E-2.

These Regions are discussed in detail in the following pages. Table 1.1 shows for each Electric Region: planned capability, projected demand, the net of purchases and sales of generating capacity; reserves, the capability that might be unavailable for various reasons, and the resulting reserve.

Kentucky Group

Electric Region 15

The Kentucky Group is projected to have a noncoincident summer peak demand of 6,049 MW. This is 3.5 percent above the actual summer 1980 demand (5,847 MW), but is 2.2 percent less than forecasted in April 1980. The average annual summer load growth was 5.1 percent during the 1977-1980 period.

The planned installed capability is 7,820 MW. This includes the Kentucky Utilities Company's 500 MW Ghent No. 3 Unit scheduled for August 1981. The planned reserve margin is 1,771 MW or 29.3 percent. Net power transfer of 364 MW into the region increases the margin to 2,135 MW or 35.3 percent. Allowance for scheduled maintenance of 63 MW during the period reduces the margin to 2,072 MW or 34.3 percent. Full forced outages during the 1977-1980 summer periods averaged 1.9 percent of installed capability. If the same magnitude of outages were to occur this summer, the reserves would be reduced to 1,923 MW or 31.8 percent. Allowance for other unavailable capability, which averaged 3.2 percent during the 1977-1980 summer periods, reduces the projected actual reserve margin to 1,673 MW or 27.7 percent. This should be more than adequate for coverage of unforeseen contingencies. If Ghent No. 3 is not available in time for the summer peak, the "actual reserve" of line 19 (Table 1.1) would be 1173 MW and the percentage reserve (line 20) would be 19.4%. This magnitude of reserve is considered adequate since it is based on significant allowance for various kinds of outages.

Indiana Group

Electric Region 16

The Indiana Group is projected to have a noncoincident summer peak demand of 9,142 MW. This is 1.8 percent above the actual summer 1980 demand (8,977 MW), but down 6.2 percent from that forecasted in April 1980. The average annual load growth during the 1977-1980 summer periods was 2.5 percent.

The planned installed capability is 11,649 MW. There is no additional major capacity planned for installation during the summer period. The planned reserve margin is 2,507 MW or 27.4 percent. Net power transfer of 635 MW into the region increases the margin to 3,142 MW or 34.4 percent. Allowance for scheduled maintenance of 524 MW reduces the margin to 2,618 MW or 28.6 percent. Full forced outages during the 1977-1980 summer periods averaged 5.8 percent of installed capability. If the same magnitude of outages were to occur this summer, the reserves would be a 1,942 MW or 21.2 percent. Allowance for other unavailable capability, which averaged 7.6 percent during the 1977-1980 summer periods, reduces the projected margin to 1,057 MW or 11.6 percent. This should be sufficient for coverage of unforeseen contingencies.

Michigan Electric Coordinated Group (MECS)

Electric Region 18

The Michigan Electric Coordinated Group (MECS) is projected to have a noncoincident summer peak demand of 12,087 MW. This is 0.9 percent above the actual summer 1980 demand (11,983 MW) and is down 8.2 percent from that forecasted in April 1980. The decrease in summer peak demand from 1977 to 1980 was equivalent to an average annual decrease of 1.8 percent. The economic condition of the area is greatly dependent upon the auto industry, which has been depressed for the last several years, partly accounting for the decrease in the rate of load growth.

The planned installed capability is 15,912 MW. There is no additional major capacity planned for installation during the summer period. The planned reserve margin is 3,825 MW or 31.6 percent. Net power transfer of 614 MW out of the region reduces the margin to 3,211 MW or 26.6 percent. Allowance for scheduled maintenance of 796 MW during the summer period reduces the reserve margin to 2,415 MW or 20.0 percent. Full forced outages during the 1977-1980 summer periods averaged 4.6 percent of installed capability. If the same magnitude of outages were to occur this summer, the reserves would be reduced to 1,683 MW or 13.9 percent. Allowance for other unavailable capability, which averaged 5.5 percent during the 1977-1980 summer periods, reduces the projected actual reserve margin to 808 MW or 6.7 percent, which appears adequate for coverage of other contingencies.

Allegheny Power System (APS)

Electric Region 1

The Allegheny Power System, Inc. (APS) is the parent company of an integrated electric system comprising the properties of the Monongahela Power Company, the Potomac Edison Company, West Penn Power Company, and their subsidiaries. The three operating companies serve over 1 million customers in southwestern and north central Pennsylvania, the northern portion of West Virginia, the western portion of Maryland and a small portion of northwestern Virginia.

The Allegheny Power System is winter peaking. The peak forecast for the summer 1981 is 4,900 megawatts. This is 3 megawatts less than the actual 1980 summer demand, and 372 MW less than the 1980-81 winter peak. The summer peak demand has shown an average annual growth of 2.5% for the last four years in the APS area.

Planned capability to meet the expected summer peak load is 7,419 megawatts. No major additions are included in the planned capability for the coming summer season. Over 99 percent of current generating capability as shown on Table 1A.2 is vested in coal-fired steam generation. There are no nuclear units installed on the system, and hydroelectric and oil-fired generation are insignificant. Table 1A.3 shows gas and oil use projections for July 1981 and actual data for July 1980. Though oil consumption is comparatively small it is expected to decline.

Capacity out for scheduled maintenance and full forced outages over the past four summer seasons each averaged 9.5% of installed capacity. Other unavailable capability averaged 11.2%. Calculated scheduled maintenance for the coming season, based on a four year average is 704 MW, shown in Table 1.1, line 9. The four-year average full forced outage of 704 MW is included in Table 1.1 line 13, as representative of the forced outage that could occur for APS. Other unavailable capability of 831 MW is included on Table 1.1 line 17. There has been a substantial increase in the APS forced outage rate during the period 1977-1979 as a result of persistent and lengthy outages of the larger units on the system. However, in 1980, for the first time in four years, APS experienced no forced outages at the time of their summer peak.

Pleasants No. 2 unit, installed in December 1980 is scheduled to be uprated 61 MW in July.

Scheduled contract purchases during the summer period include a firm 300-megawatt diversity delivery to Virginia Electric and Power Company (VEPCO) and a nonfirm purchase of 153 megawatts from the Ohio Valley Electric Company, resulting in a net export of 147 MW. The 300 megawatts to VEPCO is to be returned during the winter peak period.

As indicated in Table 1.1, for summer 1981 the APS Region's planned reserves of 51.4 percent, and the possible available reserves of 19.7 percent, respectively, are adequate. The actual reserves could be 133 MW or 2.7%, if the previous high incidence of forced outages as occurred in 1978 and 1979 is again experienced. This reserve level, after consideration of all possible outages, is marginal.

For the 1981 summer season, no major transmission lines are scheduled for completion. The transmission system is adequate to cover load commitments for the period, with no areas posing stability problems.

American Electric Power Group (AEP)

Electric Region 2

The American Electric Power System Region includes American Electric Power Company, Buckeye Power, Inc., Ohio Valley Electric Corporation, Columbus & Southern Ohio Electric Company, and the Richmond Power and Light Municipal. The American Electric Power Company is an electric utility holding company comprising seven wholly owned subsidiary companies operating in parts of seven states; Ohio, Indiana, Michigan, West Virginia, Virginia, Kentucky and Tennessee. This includes the recently acquired properties of Columbus and Southern. This report reflects forecast figures for C&SOE Co. and the previous regional figures have been adjusted for C&SOE Co. for comparison purposes. Buckeye Power, Inc. is essentially an association of all the electric cooperatives in the State of Ohio. The Ohio Valley Electric Corporation (OVEC) was originally formed by a consortium of ten electric companies in ECAR to provide electric power to the Department of Energy's Uranium Enrichment Plant in Portsmouth, Ohio. The Richmond, Ohio Municipal system has been included in this report for the first time.

The AEP region is a winter peaking area. The peak forecast for the summer 1981 is 15,196 megawatts. This is a 1.7 percent increase over the actual peak of the previous summer, and a decline of 3.3 percent from the summer peak of 1979. Peaks in this region have fluctuated because of weather conditions, as would be expected, and also because of the varying load requirements of DOE's Portsmouth nuclear processing plant. The plant's load requirements are normally supplied by Ohio Valley Electric Corp. (OVEC), a consortium of electric utilities who are obligated to furnish whatever generating capacity is needed beyond what is available from the two OVEC plants. AEP, a member of the consortium, is a major contributor when additional power is required.

Planned capability to meet the coming summer peak load is 24,733 megawatts. No major capacity additions are included in the planned capability for this season. Table 1B.2 indicates actual and projected generation for July 1980 and July 1981 respectively. Nuclear generation is expected to increase as a percentage of total generation. Oil consumption is limited to startup and no major plants used heavy oil in 1980.

Almost 88 percent of the current capability in the region is coal-fired steam capacity, and 8.5 percent is nuclear. AEP's large planned reserves in coal-fired generation, and a strong transmission system, are used to advantage by selling capacity to other utilities in the region.

Capacity out for scheduled maintenance over the past four summer seasons averaged 8.1%; full forced outages and unavailable capability averaged 4.7% and 5.7% respectively. Calculated forced outage for the coming summer season (percentage-based) is 1,158 megawatts; this is shown in Table 1.1, line 13, as representative of the probable forced outage. The unavailable capability has been included in Table 1.1 line 17.

The AEP group has no contracts with systems in Reliability Councils adjoining ECAR for scheduled transfers of power. However, there are many firm and nonfirm contracts with other companies in ECAR. As shown in Table 1.1 for the summer the AEP group planned reserves are 62.8%. Actual reserves after possible unit outages for the Region could drop to 23.1%. This should be sufficient to meet the load responsibility of the AEP system, and in addition meet deficits in other ECAR systems should they develop.

A critical transmission line, the 765 Kv Gavin-Culloden line, which is needed to carry the output of the Gavin-Mountaineer Generating Complex (3900 MW) to various load centers on the AEP system, is delayed as a result of litigation. It is expected to become operational in December 1982. No new major transmission lines are scheduled for service during the summer peak load season.

Cincinnati-Dayton Group (CD)

Electric Region 14

This region includes the Cincinnati Gas & Electric Co., the Dayton Power and Light Company and the municipal system of Hamilton, Ohio. Hamilton has not reported regularly but is included in the present data. Columbus & Southern Ohio Electric Company, formerly a member of this group and part of the Electric Region for operating purposes, has been purchased by American Electric Power System and is now included in the AEP area, instead of Electric Region 14. Historical data used in this report has been adjusted to reflect this change.

The CD group is summer peaking. The peak forecast for the summer 1981 is 5,352 megawatts. This represents a growth of 1.7 percent above the previous summer season, and 7.6 percent above the peak of 1979.

Planned capability to meet the coming summer peak load is 6,813 megawatts. East Bend #2, a 600 MW coal fired steam unit became commercial in March 1981 and will be available for the summer season. The unit is jointly owned by Cincinnati Gas & Electric and Dayton Power & Light. Zimmer No. 1, the first nuclear unit to be installed in the Region, originally scheduled for January 1981, has been rescheduled for June 1982 and is not included as available for the peak period of 1981.

Ninety-nine percent of the current capability of the area is coal-fired capacity; the remainder is oil and gas. There is only one small hydro station, and no nuclear facilities, in this Electric Region, at this time.

Table 1D.3 shows gas and oil projections for July 1981 and actual data for July 1980. All of the oil used is light oil for start-up. The forecast increase in oil is due to the installation of East Bend #2.

Capacity out for scheduled maintenance over the past four summer seasons averaged 8.1%, full forced outages averaged 4.7% and unavailable capacity averaged 8.5% as shown on Table 1D.4. Calculated scheduled maintenance for the coming summer season based on this average is 552 megawatts. The four-year average full forced outage is included in Table 1.1 line 13, as representative of the forced outage that could occur for CD. Other unavailable capability is included on Table 1.1 line 17 (557 MW).

The CD Region has no firm contracts for scheduled transfers of power with systems in Reliability Councils adjoining ECAR; however, some intra-regional contracts exist.

As indicated in Table 1.1 for the summer 1981, the CD Region's planned reserves of 27.3 percent and possible available reserves of 14.1 percent, respectively, appear adequate for the coming season. If the other unavailable capability is as forecasted, the actual reserves would be 3.3 percent. This reserve would probably be sufficient to avoid major problems.

For the 1981 summer season, no major transmission lines are scheduled for completion. The transmission system is adequate to cover load commitments for the period, with no stability problems.

Central Area Power Coordination Group (CAPCO)

Electric Region 13

This region includes the Central Area Power Coordination Group (CAPCO) and the Cleveland and Bryan Municipal Systems. CAPCO consists of five investor-owned electric utilities providing service in northern Ohio and western Pennsylvania. The systems are: The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsyulvania Power Company, and the Toledo Edison Company.

CAPCO is summer peaking and the peak forecasted for the summer 1981 is 11,620 megawatts. This represents a 2.9 percent increase over the actual peak of the previous summer, and an 8.7 percent increase over the peak of the summer two years ago. The 1980 summer peak was unusually high due to extremely hot weather.

[redacted]

Table 1C.2 indicates actual generation for July 1980 and projected July 1981 data. There is a sharp change in the nuclear generation due to the Beaver Valley units going on line and the increased generation at Davis Besse. These units were not operating at full capacity in July 1980.

Approximately 77 percent of the current capability is coal-fired steam generation, 12 percent is nuclear fueled, 9 percent oil-fired and 2 percent is pumped storage.

Table 1C.3 shows gas and oil projections for July 1981 and actual data for July 1980. The forecasted reduction of 77.9% in oil use, coupled with the forecasted 92.8% reduction in oil-based energy generation, indicates that much of the reduction will in base-load oil generation. Base load units are more efficient than peaking units, therefore it appears that the remaining oil use (22.1% of the July 1980 quantity) will be utilized mainly in peaking units to provide some 7.2% of the July 1980 generation. The reduction in oil-fired base load generation will be counterbalanced by the large increase expected in nuclear generation.

Capacity out for scheduled maintenance over the past four summer seasons averaged 6.8% of installed capacity and full forced outages averaged 8.7%. Unavailable capacity averaged 11.9%. Calculated scheduled maintenance for the coming summer season based on this percentage is 1,025 megawatts. The four-year average of full forced outages is included in Table 1.1, line 13, as representative of the forced outages that could occur for the CAPCO area. Unavailable capability is included on Table 1.1 line 17. The CAPCO region has a firm contract for 300 MW of scheduled power transfer to MAAC for GPU. In addition, some intra-regional interchange contracts exist.

As indicated in Table 1.1 for summer 1981, the CAPCO Region's planned reserves of 29.9 percent and the possible available reserves of 13.2 percent, respectively, appear adequate. If. however, the historical high incidence of scheduled, forced outage other unavailable capability continues, the actual reserves would be reduced to a negative 259 megawatts or (2.2) percent. This would be inadequate for reliable service.

There are delays in the completion of two major lines that could pose problems during the 1981 summer season. The Mansfield-Juniper 345 Kv line, an extension of the Mansfield-Hanna 345 Kv Line, which was originally scheduled for service in 1977, is under litigation and an 8.7-mile section is still to be completed. The double circuit 345 Kv Juniper-Harding line was originally scheduled for December 1973; while a major portion is completed, a part of the line has been delayed by litigation and by the need to obtain a permit from the National Park Service. The projected in-service date of the Juniper-Harding line is now April 1984.

BEST DOCUMENT AVAILABLE

TABLE 1.1

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT (ECAR)
TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

		ALLEGHENY POWER SYSTEM (APS)	AMERICAN ELECTRIC POWER GROUP (AEP) /3/	CENTRAL AREA POWER COORDINATION GROUP (CAPCO)	CINCINNATI DAYTON GROUP (CD) /3/	KENTUCKY GROUP	INDIANA GROUP	MICHIGAN ELECTRIC COORDINATED GROUP (MECS)	TOTAL ECAR /4/ REGION
1.	PLANNED CAPABILITY (MW)	7419	24733	15089	6813	7820 5/	11649	15912	89435 5/
2.	PEAK DEMAND (MW)	4900	15196	11620	5352	6049	9142	12087	64346
3.	PLANNED RESERVES (MW) (1-2)	2519	9537	3469	1461	1771	2507	3825	25089
4.	PLANNED RESERVES (%) (3/2) X 100	51.4	62.8	29.9	27.3	29.3	27.4	31.6	39.0
5.	NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	-147	-1474	401	166	364	635	-614	-669
6.	TOTAL CAPABILITY (MW) (1+5)	7272	23259	15490	6979	8184	12284	15298	88766
7.	TOTAL RESERVES (MW) (6-2)	2372	8063	3870	1627	2135	3142	3211	24420
8.	TOTAL RESERVES (%) (7/2) X 100	48.4	53.1	33.3	30.4	35.3	34.4	26.6	38.0
9.	SCHEDULED MAINTENANCE (MW) /1/	704	1996	1025	552	63	524	796	5660
10.	CAPABILITY AFTER MAINTENANCE (MW) (6-9)	6568	21263	14465	6427	8121	11760	14502	83106
11.	RESERVES AFTER MAINTENANCE (MW) (10-2)	1668	6067	2845	1075	2072	2618	2415	18760
12.	RESERVES AFTER MAINTENANCE (%) (11/2) X 100	34.0	39.9	24.5	20.1	34.3	28.6	20.0	29.2
13.	FULL FORCED OUTAGES (MW) /1/	704	1158	1311	320	149	676	732	5050
14.	CAPABILITY AFTER FULL FORCED OUTAGES (MW) (10-13)	5864	20105	13154	6107	7972	11084	13770	78056
15.	RESERVES AFTER FULL FORCED OUTAGES (MW) (14-2)	964	4909	1534	755	1923	1942	1683	13710
16.	RESERVES (%) AFTER FULL FORCED OUTAGES (15/2) X 100	19.7	32.3	13.2	14.1	31.8	21.2	13.9	21.3
17.	OTHER UNAVAILABLE CAPABILITY (MW) /1/ /2/	831	1405	1793	579	250	885	875	6618
18.	ACTUAL CAPABILITY (MW) (14-17)	5033	18700	11361	5528	7722	10199	12895	71438
19.	ACTUAL RESERVES (MW) (18-2)	133	3504	-259	176	1673	1057	808	7092
20.	ACTUAL RESERVES (%) (19/2) X 100	2.7	23.1	-2.2	3.3	27.7	11.6	6.7	11.0

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM-12E2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

/3/ COLUMBUS & SOUTHERN OHIO ELECTRIC COMPANY IS NOW INCLUDED IN THE AEP GROUP.

/4/ ALL LIAISON MEMBER SYSTEMS HAVE BEEN INCORPORATED WITH APPROPRIATE BULK POWER MEMBER SYSTEMS FOR THE PURPOSE OF THIS REPORT.

/5/ INCLUDES GHENT NO. 3, 500 MW, SCHEDULED FOR AUGUST 1981.

Table 1A.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE ALLEGHENY POWER SYSTEM (APS)

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
Hydro	11,951	0.4	10,200	0.4
Coal	2,775,013	98.8	2,842,900	99.3
Gas	1,201	0.0	-	-
Oil	21,413	0.8	9,800	0.3
Nuclear	-	-	-	-
Pump Storage (Net)	-	-	-	-
Total	2,809,578	100.0	2,862,900	100.0

SOURCE: ACTUAL DATA -FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1A.3
GAS AND OIL USE PROJECTION FOR JULY 1981 VS ACTUAL GAS AND OIL USE FOR JULY 1980 ALLEGHENY POWER SYSTEM (APS)

FUEL TYPE	JUL. 1981 PROJECTION	JUL. 1980 ACTUAL	PERCENT 7-81/7-80
Gas (MCF)	-	13	-
Oil (BBLS)	16,330	46,165	35.4

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1A.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980 ALLEGHENY POWER SYSTEM APS

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
Aug. 1977	596	9.2	315	4.8	632	9.7
Aug. 1978	500	7.7	971	14.9	714	11.0
Aug. 1979	669	9.5	1280	18.1	554	7.8
July 1980	816	11.5	0	0	1140	16.1
4-Yr. Average		9.5		9.5		11.2

SOURCE: FPC FORM 12E-2

Table 1B.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
AMERICAN ELECTRIC POWER GROUP (AEP)

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH) *	% OF TOTAL
Hydro	39,640	0.3	51,000	0.4
Coal	12,654,141	96.1	11,530,574	90.9
Gas	2,298	0.0	-	-
Oil	44,828	0.3	-	-
Nuclear	427,116	3.2	1,121,000	8.8
Pump Storage (Net)	NA	NA	(16,000)	(0.1)
Total	13,168,023	100.0	12,686,574	100.0

*BUCKEYE POWER INC. DATA ARE NOT REPORTED IN ERA FORM 160

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1B.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
AMERICAN ELECTRIC POWER GROUP (AEP)

FUEL TYPE	JUL. 1981 PROJECTION	JUL. 1980 ACTUAL	PERCENT 7-81/7-80
Gas (MCF)	-	39	-
Oil (BBLS)	64,000	75,365	84.9

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1B.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980
AMERICAN ELECTRIC POWER GROUP (AEP)

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
July 1977	1335	5.9	1090	4.9	1022	4.5
July 1978	1636	6.5	1910	7.6	1787	7.1
Aug. 1979	2260	9.2	655	2.7	1373	5.6
July 1980	2631	10.7	850	3.4	1368	5.5
4-Yr. Average		8.1		4.7		5.7

SOURCE: FPC FORM 12E-2

[redacted]

Table 1C.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
CENTRAL AREA POWER COORDINATION GROUP (CAPCO)

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
Hydro	-	-	-	-
Coal	4,438,017	97.6	4,545,798	84.0
Gas	917	0.0	-	-
Oil	72,779	1.6	5,208	0.1
Nuclear	35,164	0.8	860,743	15.9
Pump Storage (Net)	-	-	-	-
TOTAL	4,546,877	100.0	5,411,749	100.0

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1C.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
CENTRAL AREA POWER COORDINATION GROUP (CAPCO)

FUEL TYPE	JUL. 1981 PROJECTION	JUL. 1980 ACTUAL	PERCENT 7-81/7-80
Gas (MCF)	-	18	-
Oil (BBLS)	31,267	141,589	22.1

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1C.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980
CENTRAL AREA POWER COORDINATION GROUP (CAPCO)

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
July 1977	414	3.0	863	6.2	1138	8.2
July 1978	1005	6.4	1571	10.0	2172	13.9
July 1979	830	5.2	1631	10.3	2177	13.8
July 1980	2034	12.5	1360	8.4	1879	11.6
4-YR. AVERAGE		6.8		8.7		11.9

SOURCE: FPC FORM 12E-2

[redacted]

Table 1D.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
CINCINNATI-DAYTON GROUP (CD)

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
Hydro	757	0.0	600	0.0
Coal	2,486,575	97.7	2,343,750	98.4
Gas	16,463	0.6	6,600	0.3
Oil	42,148	1.7	31,035	1.3
Nuclear	-	-	-	-
Pump Storage (Net)	-	-	-	-
TOTAL	2,545,943	100.0	2,381,985	100.0

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1D.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
CINCINNATI-DAYTON GROUP (CD)

FUEL TYPE	JUL. 1981 PROJECTION	JUL. 1980 ACTUAL	PERCENT 7-81/7-80
Gas (MCF)	149	259	57.5
Oil (BBLS)	94,097	80,134	117.4

SOURCE: ACTUAL DATA - FERC FORM 4
PROJECTED DATA - ERA FORM 160

Table 1D.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980
CINCINNATI-DAYTON GROUP (CD)

MONTH-YEAR	SCHEDULED MAINTENANCE (MW)	SCHEDULED MAINTENANCE % OF INSTALL CAPACITY	FULL FORCED OUTAGES (MW)	FULL FORCED OUTAGES % OF INSTALL CAPACITY	OTHER UNAVAILABLE CAPACITY (MW)	OTHER UNAVAILABLE CAPACITY % OF INSTALL CAPACITY
July 1977	432	7.2	123	2.0	417	6.9
July 1978	962	14.6	124	1.9	589	9.0
Aug. 1979	589	9.0	389	5.9	731	11.1
July 1980	104	1.6	602	9.1	468	7.1
4-YR. AVERAGE		8.1		4.7		8.5

SOURCE: FPC FORM 12E-2

2. Electric Reliability Council of Texas (ERCOT)

Electric Region 23

The members of the Electric Reliability Council of Texas (ERCOT) supply electric power within the State of Texas only and do not as yet operate in synchronism with any of the other eight Reliability Council areas. The entire ERCOT area is included in the Texas Interconnected Systems Group (TIS) (Electric Region 23). The area is internally divided into the North and South Texas areas for planning and operating purposes, and each area is monitored by a security center. There are also seven control centers in the South Texas area and three in the North Texas area.

ERCOT usually experiences its peak electric load in July or August during periods of prolonged hot dry weather. Its winter peak occurs in December or January and is approximately 75 percent of the summer peak load. The 1981 non-coincident summer peak demand for Region 23 is projected by ERCOT to be 32,825 MW, which is an increase of approximately 2.5 percent over the actual non-coincident 1980 peak. The increase from 1979 to 1980 was 12.6 percent. The large actual load growth of 12.6 percent was the result of two consecutive summers of abnormal weather conditions: 1979 was below average and 1980 was extremely hot and dry. The estimated peak demand of 32,825 MW is based on average weather conditions, but according to long range weather predictions the 1981 summer period will again be hot and dry. Based on these predictions Region 23 could experience another year of above average load growth. The predicted Actual Reserve for the 1981 summer peak period is 5,677 MW or 17.3 percent of peak demand (see Table 2.1). If Region 23 experienced a load growth in 1981 approaching the 1979-80 growth, actual reserves could drop to 2,107 MW or 5.8 percent.

The existing high voltage transmission system is at the 345 kV level and extends east to west in the North Texas portion of the area and north to south between the North and South Texas areas. The 345 kV system between North and South Texas was constructed primarily for reliability purposes and until recently was not used for economy energy transactions.

Texas is presently isolated electrically from other electric regions in the nation. The Central & South West Corporation (CSW) has petitioned the Federal Energy Regulatory Commission (FERC) to order ERCOT to interconnect with the Southwest Power Pool (SPP). As a result of this petition, systems in ERCOT and SPP have signed an interconnection agreement which has not yet been approved by FERC. The agreement calls for construction of two direct current transmission lines, one in East Texas and one from Oklahoma into West Texas. Consummation of this interconnection could have some effect on the load and supply situation in future years. At the present time the legal proceedings are still within FERC.

The data in Table 2.1 was derived from information reported by ERCOT in its ERA-411 Report submitted April 1, 1981.* Full forced outages and other unavailable capability were calculated by DOE based upon 1977-80 historical averages at the time of the summer peaks. Information to calculate these averages was obtained from FPC Form 12E-2 reports filed by the ERCOT systems. These figures are 3.9 percent and 5.9 percent, respectively. Scheduled maintenance is used as projected by ERCOT since the systems have firm plans for removing capacity for maintenance during the upcoming summer peak period. The projected actual reserve margin for the 1981 summer peak period is 17.3 percent. This margin includes the effect of 4,660 MW unavailable (10.8 percent of planned capability) which consists of scheduled maintenance, full forced outages and other unavailable capability.

ERCOT is highly dependent upon natural gas for generation. There is installed or proposed for operation a total of 32,459 MW of gas-fired generation for the summer of 1981, which amounts to 75 percent of total capability in Region 23. This capability is considered dependable since cutbacks in natural gas supplies generally only occur during the winter months due to home heating priority. Fuel supplies appear more than adequate for this summer. The 230 MW of hydroelectric capacity and the 102 MW of oil-fired capacity are not expected to present fuel supply problems.

* The Planned Capability on Line 1 of Table 2.1 is 19 MW less than the Net Dependable Capability listed for the summer of 1981 on Line 1 of Item 3-A in ERCOT's report. The capability in Table 2.1 was obtained by adding to the existing capability from ERCOT's Item 2-A the changes scheduled to occur before the 1981 summer peak period as shown in Item 2-B.

Although presently isolated, ERCOT shows net imports of 150 MW (Line 5 of Table 2.1). This is due to imports from non-member systems within the ERCOT region and from systems outside of the region that supply a part of the West Texas Utilities Co. system, located within the ERCOT area but not connected to the ERCOT (Texas Interconnected) system. The summer load-supply situation appears to be satisfactory. Fuel should be available in sufficient quantity to supply all energy requirements.

TABLE 2.1

ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

MW OR PERCENT	TEXAS INTERCONNECTED SYSTEMS GROUP (TIS)
1. PLANNED CAPABILITY	43012
2. PEAK DEMAND	32825
3. PLANNED RESERVES (1-2)	10187
4. PLANNED RESERVES (%) (3/2)X100	31.0
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	150
6. TOTAL CAPABILITY (1+5)	43162
7. TOTAL RESERVES (6-2)	10337
8. TOTAL RESERVES (%) (7/2)X100	31.5
9. SCHEDULED MAINTENANCE	445
10. CAPABILITY AFTER MAINTENANCE (6-9)	42717
11. RESERVES AFTER MAINTENANCE (10-2)	9892
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	30.1
13. FULL FORCED OUTAGES 1/	1677
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	41040
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	8215
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	25.0
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	2538
18. ACTUAL CAPABILITY (14-17)	38502
19. ACTUAL RESERVES (18-2)	5677
20. ACTUAL RESERVES (%) (19/2)X100	17.3

1/ OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM-12E2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

3. Mid-Atlantic Area Coordination Council (MAAC)

Pennsylvania-New Jersey-Maryland Interconnection (PJM)

Electric Region 5

The Mid-Atlantic Area Coordination Council (MAAC) is operated as a single system under the Pennsylvania-New Jersey-Maryland Interconnection (PJM) pooling agreement. PJM coordinates the bulk power supply of its eleven investor-owned utility members, and through associate membership, the municipals, electric cooperatives, and small investor-owned electric systems, in the MAAC region. The MAAC region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small portion of Virginia. There are no Electric Region subdivisions of MAAC.

The PJM peak load forecast (including interruptible load) for summer 1981 is 34,102 megawatts, which includes the Allegheny Cooperative Load of 107 MW (See Table 3.1). This is a 2.3% decrease below the actual peak (computed on the same basis) of the previous summer. The 1980 peak was almost 2,800 megawatts higher than the 1979 summer peak, due primarily to sustained unusually hot weather. More normal weather is reflected in the lower peak forecast for summer 1981. As a result of heavy air conditioning loads, PJM is a weather-sensitive summer peaking area; the summer peak can occur in any summer month.

Planned capability to meet the 1981 summer peak load forecast is 46,176 megawatts. Included in the planned capability are TMI 1 and TMI 2, 1,114 megawatts of new capacity and retirements of 40 megawatts. Salem No. 2, a 1,114 megawatt nuclear unit orginally scheduled for initial operation in January, has been delayed until April 1981 and has been included as being available for the summer season. TMI 1 and TMI 2 are included in Line 17 of Table 3.1 with other unavailable capability and therefore are excluded from the actual reserves of Line 20.

Coal-fired generation represented 58% of the total energy produced in July 1980 while oil and gas-fired generation combined represented 23%, nuclear fueled capacity 19% and hydro generation was less than 1%. Table 3.2 indicates actual July 1980 and projected July 1981 generation by fuel type based on ERA-Form 160. Table 3.3 provides fuel-use projections for oil and gas for July 1981 and actual use for July 1980. The rapid growth in the peak requirements between summer 1979 and summer 1980 may indicate a need for additional peaking capacity in the immediate future. If in 1981 the area experiences the prolonged heatstorm that it experienced in 1980, shortfalls in peaking capacity may be evident. The loss of the Three Mile Island nuclear units has increased PJM dependence on older, higher cost capacity, and has made it economically advantageous to import short-term firm energy from neighboring pools.

PJM has scheduled for its peak demand period firm receipts from NPCC: Ontario Hydro-200 MW, Power Authority of the State of N.Y.-107MW, and from ECAR: American Electric Power (thru Cleveland Electric Illuminating Company) 300 MW. The GPU Lake Erie Technical Data Study states that a letter of intent was signed on 2/10/81 for 254MW of additional capacity from Ontario Hydro thru the Michigan pool and CAPCO to GPU, although no firm contract has been executed. This import has not been included as a firm receipt during the summer peak in Table 3.1. The roundabout route proposed for this purchase is due to lack of sufficient transmission capacity on the more direct route from Ontario Hydro through New York.

Table 3.4 shows the average generating capacity unavailable at the time of the summer system peak demand for the past four summers as a percent of installed capacity, and the four-year average. The four-year average scheduled maintenance rate of 3.0% is less than the 4.4% forecasted by PJM for summer 1981. The PJM forecast was the one used for developing Table 3.1. The four-year average full forced outage rate of 10.9%, from Table 3.4, is included on line 13 of Table 3.1 as representative of the full forced outages that may occur on the PJM system. The four-year average other unavailable capacity* rate of 3.7% is less than that forecasted by PJM for summer 1981 of 4.8%. The higher figure was used in Table 3.1 as being more appropriate. The 35.4% planned reserve based on peak demand, however, is well above the PJM agreement criterion of 22 percent for planned reserves. With allowance for all possible outages of 20.2% of planned capability, MAAC would have an actual reserve of 9.9% as indicated on Table 3.1 for summer 1981. The MAAC area's reserves should be adequate to meet load responsibility. However, the PJM 1981 forecasted peak is 687MW less than the actual 1980 peak and the actual 1980 peak was reduced approximately 775MW as a result of voltage reduction and public appeals. If the 1981 peak is higher than estimated or if the Salem Unit #2 is further delayed beyond the summer peak, the possibility exists for voltage reductions or more serious consequences. This could be further complicated in the MAAC area because the transmission system lacks reserve capability for large-scale additional transfers to the eastern portion without adversely affecting the reliability for emergency interchange. This has created some operational problems related to voltage and reactive limitations on internal MAAC transmission. Load flow studies and on-line reactive contingency analyses are being undertaken by PJM to find a remedy for this situation. The Hosensack-Elroy 500 Kv line was completed on March 22, 1981 and will provide some relief for PJM transmission problems. The Baltimore-Washington 500 Kv loop, which is still in litigation, is a critical transmission line for the near term period, that could provide some relief for the PJM transmission problem if it were in operation.

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* Including TMI 1 and TMI 2.

Fig. 3.1 indicates the non-simultaneous emergency transfer capabilities between Reliability Councils for 1981, the number of inter-regional transmission lines 345 Kv and higher, and firm power scheduled at the time of the MAAC summer peak.

TABLE 3.1

MID ATLANTIC AREA COUNCIL (MAAC)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR THE SUMMER 1981 PEAK PERIOD

	PENNSYLVANIA NEW JERSEY MARYLAND INTERCONNECTION (PJM)	TOTAL MAAC[1] REGION
1. PLANNED CAPABILITY (MW)	46176	46176
2. PEAK DEMAND (MW)	34102	34102
3. PLANNED RESERVES (MW)(1-2)	12074	12074
4. PLANNED RESERVES (%) (3/2) X 100	35.4	35.4
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW)	607	607
6. TOTAL CAPABILITY (MW) (1+5)	46783	46783
7. TOTAL RESERVES (MW) (6-2)	12681	12681
8. TOTAL RESERVES (%) (7/2) X 100	37.2	37.2
9. SCHEDULED MAINTENANCE (MW) [2]	2050	2050
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	44733	44733
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	10631	10631
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	31.2	31.2
13. FULL FORCED OUTAGES (MW) [3]	5033	5033
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	39700	39700
15. AVAILABLE RESERVES (MW) (14-2)	5598	5598
16. AVAILABLE RESERVES (%) (15/2) X 100	16.4	16.4
17. OTHER UNAVAILABLE CAPABILITY (MW) [4]	2229	2229
18. AVAILABLE CAPABILITY (MW) (14-17)	37471	37471
19. ACTUAL RESERVES (MW) (18-2)	3369	3369
20. ACTUAL RESERVES (%) (19/2) X 100	9.9	9.9

[1] ALL LIAISON MEMBER SYSTEMS HAVE BEEN INCORPORATED WITH APPROPRIATE BULK POWER MEMBER SYSTEMS FOR THE PURPOSE OF THIS REPORT.

[2] AS REPORTED BY PJM.

[3] COMPUTED AT THE FOUR YEAR AVERAGE SUMMER FORCED OUTAGE RATE. FROM FPC FORM 12E-2 DATA.

[4] OTHER UNAVAILABLE CAPABILITY IS PARTIAL UNIT FORCED OUTAGES,DERATINGS AND THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER,OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE. THIS INCLUDES TMI #1 AND TMI #2. AS REPORTED BY PJM.

BEST DOCUMENT AVAILABLE

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TABLE 3.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
MID ATLANTIC AREA COUNCIL

Fuel Type	Actual July 1980 Generation (MWH)	% of Total	Projected July 1981 Generation (MWH)	% of Total
Hydro	68,000	0.5	168,014	1.0
Coal	8,406,000	57.8	9,117,373	57.8
Gas	876,000	6.0	848,197	5.4
Oil	2,428,000	16.7	2,159,936	13.7
Nuclear	2,754,000	19.0	3,524,509	22.3
Pump Storage (Net)	NA	NA	(36,616)	(0.2)
Other	-	-	-	-
Total	14,532,000	100.0	15,781,413	100.0

Source: Actual Data - Electric Power Monthly-August 1980
Projected Data - ERA Form 160

TABLE 3.3
GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
MID ATLANTIC AREA COUNCIL

Fuel Type	July 1981 Projection	July 1980 Actual	Percent 7-81/7-80
Gas (MCF)	10,032	10,568	94.9
Oil (BBLS)	4,018,652	4,441,000	90.5

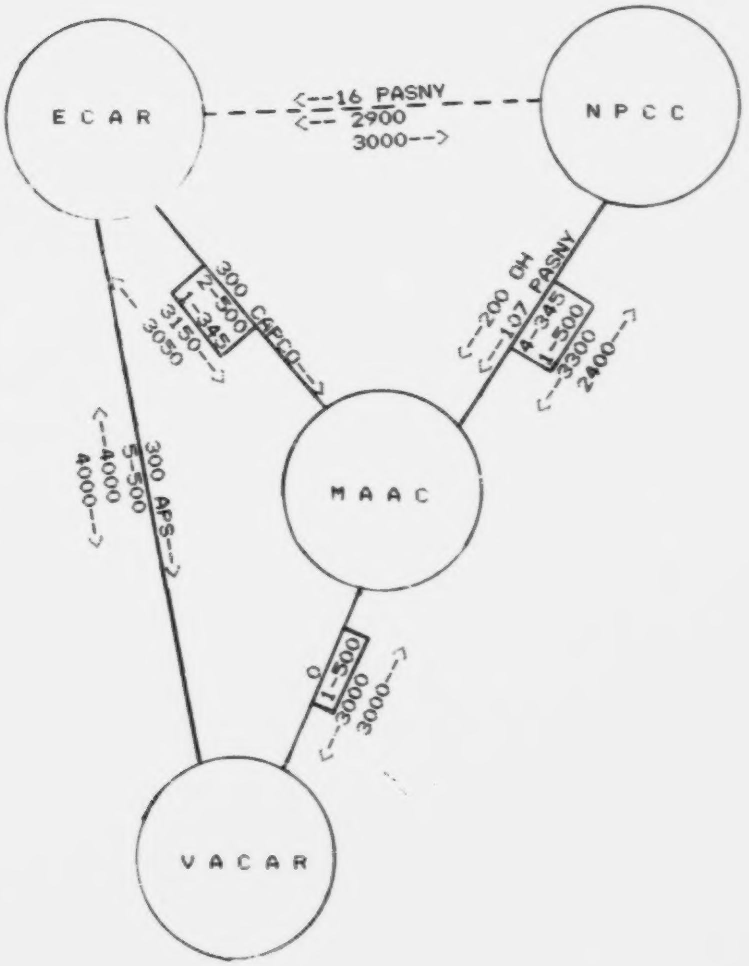
Source: Actual Data - Electric Power Monthly-August 1980
Projected Data - ERA Form 160

TABLE 3.4
AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE SUMMER SYSTEM PEAK DEMAND 1977, 1978, 1979, 1980
MID ATLANTIC AREA COUNCIL

Month-Year	Scheduled Maintenance		Full Forced Outages		Other Unavailable Capacity	
	(MW)	% of Install Capacity	(MW)	% of Install Capacity	(MW)	% of Install Capacity
July 1977	1035	2.2	5928	12.4	2163	4.5
August 1978	1559	3.3	1907	4.0	2548	5.3
August 1979	1459	3.0	6519	13.4	725	1.5
July 1980	1729	3.6	6768	13.9	1602	3.3
4-Yr. Average		3.0		10.9		3.7

Source: FPC Form 12E-2

TRANSFER CAPABILITY BETWEEN MAAC AND ADJACENT COUNCILS


ECAR
NPCC
MAAC
VACAR
<--16 PASNY
<-- 2900
3000-->
300 CAPCO-->
2-500
1-345
<--3150
3050-->
<--200 OH
<--107 PASNY
4-345
1-500
<--3300
2400-->
300 APS-->
5-500
<--4000
4000-->
0
1-500
<--3000
3000-->

50--> FIRM POWER TRANSFER IN MEGAWATTS.
1-500 NUMBER OF INTERCONNECTIONS AND KILOVOLTS.
3000--> EMERGENCY TRANSFER CAPABILITY.
------ NO PHYSICAL CONNECTION BETWEEN COUNCILS WITHIN THE UNITED STATES.

FIGURE 3.1

4. MID-AMERICA INTERPOOL NETWORK (MAIN)

The MAIN area includes all of the State of Illinois and parts of Michigan, Wisconsin and Missouri. The area is subdivided for purposes of this report, into Electric Region 6, Commonwealth Edison Company Area (ER6-CECO); Electric Region 17, Illinois-Missouri Group (ER17-ILLMO); and Electric Region 19, Wisconsin-Upper Michigan Systems Group (ER19-WUMS).

The noncoincident summer peak load of the MAIN region is projected to be 34,993 MW; this is 3.2 percent greater than the actual summer 1980 demand (33,915 MW) and is reduced 980 MW or 2.7 percent from the forecast made in April 1980. Most of the reduction in the forecast occurs in Electric Region 6, Commonwealth Edison Company area. During the summer periods of 1977-1980, the peak demand grew at an effective compound rate of 1.8 percent.

The planned summer capability is estimated to be 41,106 MW. No major new capacity is scheduled to be completed during the summer. The planned reserve margin is forecasted to be 6,113 MW or 17.5 percent of the projected peak demand. Net power transfer of 759 MW into the region increases the margin to 6,872 MW or 19.6 percent. Allowance for scheduled maintenance of 1,029 MW reduces the reserve margin after maintenance to 5,843 MW or 16.7 percent. Full forced outages during the 1977-1980 summer periods averaged 3.8 percent of installed capability; if forced outages of this magnitude were to occur this summer, the reserve margin would be reduced to 4,288 MW or 12.3 percent. Allowance for other unavailable capability, which averaged 11.9 percent over the 1977-1980 summers, reduces the projected actual reserve margin to 0.3 percent.

In addition to MAIN's installed reserve capability, emergency transfer capability exists between MAIN and adjacent Reliability Council areas through several high voltage ties. Recent operating studies by MAIN indicate the following non-simultaneous values for emergency assistance above contracted schedules:

ECAR to MAIN - 2,900 MW   SERC to MAIN - 1,800 MW*

MARCA to MAIN - 400 MW   SPP to MAIN - 2,400 MW

* After implementation of an operating guide.

Commonwealth Edison Company
Electric Region 6

Within the MAIN region, Electric Region 6 (Commonwealth Edison Company Area) is projected to have a summer peak demand of 15,047 MW. This is 5.4 percent above the actual summer 1980 demand (14,275 MW) and is reduced 784 MW or 5.0 percent from the forecast made in April 1980. During the 1977-1980 summer periods, the area showed essentially no growth in peak demand.

The planned capability of 16,499 MW results in a planned reserve margin of 1,452 MW or 9.6 percent of the expected peak demand. Power transactions with other utilities planned during the period consists of 624 MW of firm commitment from the Michigan Systems in ECAR. This increases the total reserves to 2,076 MW or 13.8 percent. Based on the 1977-1980 historic summer rate of 2.0 percent of generating capability being on scheduled maintenance during the occurrence of the peak load, capability unavailable because of maintenance amounts to 330 MW, resulting in a reserve margin after maintenance of 1,746 MW or 11.6 percent.

Full forced outages over the 1977-1980 summer periods averaged 7.2 percent of installed capability during the peak occurrence. If the forced outages which occur this summer approximate the average which occurred over the past four years, the reserve margin would be 558 MW or 3.7 percent. Allowance for other unavailable capability, which averaged 17.8 percent 1/ over the 1977-1980 summer periods, reduces the projected actual reserve margin to -2,379 MW or a negative 15.8 percent. There is expected to be enough other capability available within MAIN to supply emergency power, if necessary. In addition, some of the capacity scheduled for maintenance possibly could be delayed, if required.

Illinois-Missouri Group (ILLMO)
Electric Region 17

The ILLMO Region is projected to have a noncoincident summer peak demand of 12,912 MW. This is 0.3 percent less than the actual summer 1980 demand (12,946) and is reduced 127 MW or 1.0 percent from the forecast in April 1980. The load had an average annual growth of 3.4 percent for the 1977-1980 summers.

The planned installed capability of 15,693 MW results in a planned reserve margin of 2,781 MW or 21.5 percent. Net power transfers of 144 MW into the region increases the margin to 2,925 MW or 22.7 percent. Allowance for scheduled maintenance of 235 MW reduces the reserves after maintenance to 2,690 MW or 20.8 percent. Full forced outages during the summer periods of 1977-1980 averaged 1.2 percent of installed capability. Forced outages of this magnitude would reduce this summer's reserves to 2,439 MW or 18.9 percent. Allowance for other unavailable capability, which averaged 5.3 percent during the 1977-1980 summers, reduces the projected actual reserve margin to 1,607 MW or 12.4 percent. This should be adequate to cover other contingencies should they occur.

Wisconsin-Upper Michigan Systems (WUMS)
Electric Region 19

The WUMS Region is projected to have a noncoincident peak demand of 7,034 MW. This is 5.1 percent above the actual summer 1980 demand (6,694 MW) and is 69 MW or 1.0 percent less than the 7,103 MW forecasted in April 1980. The summer peak demand during 1977-1980 actually grew at a rate of 1.0 percent annually.

The planned installed capability of 8,914 MW results in a planned reserve margin of 1,880 MW or 26.7 percent. Net power transfers of 9 MW out of the region decreases the margin to 1,871 MW or 26.6 percent. Allowance for scheduled maintenance of 464 MW reduces the margin to 20.0 percent. Full forced outages during the 1977-1980 summer periods averaged 1.3 percent of installed capability. If the same magnitude of outages were to occur this summer, the actual reserves would be 1,291 MW or 18.4 percent. Allowance for other unavailable capability, which averaged 4.5 percent during the 1977-1980 summer periods, reduces the projected actual reserve margin to 890 MW or 12.7 percent. This should be adequate for coverage of contingencies.

1/ Due to partial forced outages; partial maintenance; reduced capability (derating) of some units because of the use of low-sulfur coal and environmental restrictions on cooling water temperature rise and stack gas emissions; problems with combustion turbine peaking units.

TABLE 4.1

MID-AMERICA INTERPOOL NETWORK (MAIN)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

MW OR PERCENT	COMMONWEALTH EDISON (CECO)	ILLINOIS-MISSOURI GROUP (ILLMO)	WISCONSIN-UPPER MICH. GROUP (WUMS)	TOTAL MAIN REGION
1. PLANNED CAPABILITY	16499	15693	8914	41106
2. PEAK DEMAND	15047	12912	7034	34993
3. PLANNED RESERVES (1-2)	1452	2781	1880	6113
4. PLANNED RESERVES (%) (3/2)X100	9.6	21.5	26.7	17.5
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	624	144	-9	759
6. TOTAL CAPABILITY (1+5)	17123	15837	8905	41865
7. TOTAL RESERVES (6-2)	2076	2925	1871	6872
8. TOTAL RESERVES (%) (7/2)X100	13.8	22.7	26.6	19.6
9. SCHEDULED MAINTENANCE	330	235	464	1029
10. CAPABILITY AFTER MAINTENANCE (6-9)	16793	15602	8441	40836
11. RESERVES AFTER MAINTENANCE (10-2)	1746	2690	1407	5843
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	11.6	20.8	20.0	16.7
13. FULL FORCED OUTAGES /1/	1188	251	116	1555
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	15605	15351	8325	39281
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	558	2439	1291	4288
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	3.7	18.9	18.4	12.3
17. OTHER UNAVAILABLE CAPABILITY /1/ /2/	2937	832	401	4170
18. ACTUAL CAPABILITY (14-17)	12668	14519	7924	35111
19. ACTUAL RESERVES (18-2)	-2379	1607	890	118
20. ACTUAL RESERVES (%) (19/2)X100	-15.8	12.4	12.7	0.3

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL AVERAGES AT THE TIME OF THE SUMMER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM 12E-2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

5. MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (MARCA)

Electric Region 20

The United States portion of MARCA includes all of the states of Iowa, Minnesota, Nebraska, North Dakota and portions of Illinois, Montana, South Dakota and Wisconsin. The Mid-Continent Area Power Pool (MAPP) coordinates the planning of bulk power supply and daily operations of all major utilities in the MARCA area. The Manitoba (Canada) Hydroelectric Board (MHEB) is an Associate Member of MARCA; however, its generating resources and loads have not been included in this report, except to the extent of firm transaction with MARCA members.

Two 230-Kilovolt ties between Manitoba Hydro and the MARCA transmission network could provide emergency support to the United States systems if capacity is available in Manitoba. A new 500 kV line between Manitoba and MARCA systems was energized in May 1980, which can provide additional emergency support. Recent seasonal operating studies by MAPP indicate that the MARCA bulk power system is capable of supplying firm power transfers with enough excess transfer capability for scheduling significant amounts of emergency and economy energy. Interregional nonsimultaneous emergency tranfer capabilities with the MAIN region derived from operating studies are given as 1,200 MW import and 400 MW export. Import capability from the Southwest Power Pool (SPP) is approximately 500 MW and export capability to SPP is about 900 MW.

MARCA is projected to have a noncoincident summer peak demand of 20,039 MW. This is 3.2 percent above the actual summer 1980 demand (19,412) but is 5.8 percent below that forecasted in April 1980. The load grew at an average annual rate of 3.3 percent during the 1977-1980 summer periods. Hence, the projected peak would appear to be in line with the historic growth pattern.

The planned installed capability is 27,659 MW. This includes 410 MW of the Coyote No. 1 generating unit and 675 MW of the Ottumwa No. 1 unit planned for operation in May 1981 and 550 MW of the Laramie River No. 2 unit scheduled for June 1981. The planned reserve margin is 7,620 MW or 38.0 percent. Net power transfers of 487 MW into the region increased the margin to 8,107 MW or 40.5 percent. Based on the 1977-1980 historic summer periods rate of 1.9 percent of generating capability being on scheduled maintenance during the occurrence of the peak load, capability unavailable because of maintenance amounts to 526 MW, resulting in a reserve margin of 7,581 MW or 37.8 percent. Full forced outages during the 1977-1980 summer periods averaged 5.3 percent of installed capability. If the same magnitude of outages were to occur this summer, the reserves would be 6,115 MW or 30.5 percent. Allowance for other unavailable capability, which averaged 1.8 percent over lht 30.5 percent. Allowance for other unavailable capability, which averaged 1.8 percent over the 1977-1980 summer periods, reduces the projected actual reserves to 5,617 MW or 28.0 percent. This should be more than adequate for coverage of unforeseen contingencies. If the units scheduled for May and June were not in service before the summer peak, the reserve margin would still be 3,882 MW or 14.4 percent.

TABLE 5.1
MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (MARCA)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

	MW OR PERCENT	TOTAL MARCA REGION
1.	PLANNED CAPABILITY	27,659
2.	PEAK DEMAND	20,039
3.	PLANNED RESERVES (1-2)	7,620
4.	PLANNED RESERVES (%) (3/2)X100	38.0
5.	NET TRANSACTIONS (IMPORTS-EXPORTS)	487
6.	TOTAL CAPABILITY (1+5)	28,146
7.	TOTAL RESERVES (6-2)	8,107
8.	TOTAL RESERVES (%) (7/2)X100	40.5
9.	SCHEDULED MAINTENANCE /1/	526
10.	CAPABILITY AFTER MAINTENANCE (6-9)	27,620
11.	RESERVES AFTER MAINTENANCE (10-2)	7,581
12.	RESERVES AFTER MAINTENANCE (%) (11/2)X100	37.8
13.	FULL FORCED OUTAGES /1/	1,466
14.	CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	26,154
15.	RESERVES AFTER FULL FORCED OUTAGES (14-2)	6,115
16.	RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	30.5
17.	OTHER UNAVAILABLE CAPABILITY /1/ /2/	498
18.	ACTUAL CAPABILITY (14-17)	25,656
19.	ACTUAL RESERVES (18-2)	5,617
20.	ACTUAL RESERVES (%) (19/2)X100	28.0

/1/ SCHEDULED MAINTENANCE, OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL AVERAGES AT THE TIME OF THE SUMMER PEAKS BEGINNING WITH THE 1977 SUMMER. DATA OBTAINED FROM FPC FORM 12E-2.

/2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

Northeast Power Coordinating Council (NPCC)

Electric Regions 3 and 4

The Northeast Power Coordinating Council (NPCC) includes all of New England, New York, Ontario and New Brunswick. Twenty-one utility member systems divided into four planning and operating entities or subregions -- two in the United States and two in Canada -- comprise the Council. This report addresses only the two Electric Regions in the United States portion of the Council, the New England Power Pool (NEPOOL) and the New York Power Pool (NYPP).

The non-coincident NPCC peak load forecast for the summer season 1981 as shown on line 2 of Table 6.1 is 35,843 megawatts. This is a 3.0 percent decrease below the actual peak of the previous summer, and a 2.0 percent increase over the summer peak of 1979. The summer peak of 1980 was higher than normal primarily due to unusually hot weather. NEPOOL is a winter peaking system, NYPP is a summer peaking group, and therefore some interpool diversity exists. Each pool takes advantage of inter-system diversity in establishing its reserve criteria and scheduling maintenance.

Planned capability to meet the 1981 summer peak load forecast is 51,007 megawatts. In addition NPCC has scheduled 882 MW of firm receipts from Hydro Quebec, New Brunswick and Southern Canada for the forecast period. There are no major generating additions scheduled for installation during the summer peak period.

Both U.S. areas of NPCC are heavily dependent on oil for the production of electric energy. This dependence on oil adversely impacts the cost of electric power supply. Oil-fired generation represented 43% of the total energy produced in July 1980; nuclear generation 23%; hydro 14%; coal 10% and gas and other sources 10%. Table 6.2 indicates projected generation by fuel type for July 1981 based on ERA Form 160, and actual July 1980 generation taken from the Energy Information Administration (EIA) Electric Power Monthly Report dated August 1980. Table 6.3 compares actual use of gas and oil in July 1980 with the projected use of those fuels for July 1981.

Table 6.4 shows the four year average generating capacity unavailable at the time of the summer system peak for the period 1977 through 1980. The diversity between the seasonal peaks of each regional area allows for coordination of scheduling of maintenance during the appropriate season to avoid having excessive amounts of capacity unavailable.

The NPCC four-year scheduled maintenance average was 7.7%. For summer 1981 the corresponding amount is 3,929 MW as shown on line 9 of Table 6.1. The capacity on forced outage for NPCC as shown in Table 6.1 line 13, is based on the four-year average of forced outages in megawatts; it is a representative forced outage rate that may occur in NPCC. The calculated four-year average unavailable capacity is shown on line 17 of Table 6.1.

As indicated on Table 6.1 for Summer 1981, NPCC will have adequate reserves to meet its load responsibility. The 13.1 percent reserves after all projected outages is well above the NPCC required operating reserves. Total planned reserves are 42.3% before consideration of possible outages and the net of imports and exports.

No major transmission lines are scheduled for completion prior to the 1981 peak. The transmission system appears adequate to cover load commitments for the period with no stability problem areas.

New England Power Pool (NEPOOL)
Electric Region 3

NEPOOL is the coordinating pool for the New England states; it includes over forty privately and publicly owned utilities operating in the six New England States.

NEPOOL is a winter peaking Region, though some systems in Connecticut have a summer peak. The peak load forecast for the summer of 1981 is 14,780 megawatts. This is a 1.4% decrease below the actual peak of the previous summer and 3.4% lower than the winter peak of 1980-81. The annual summer growth rate for the past 3 years has been 3.8%, while the annual winter peak growth for the same period was 3.6%. These rates reflect the general reduction in the region's economic activity.

Capability planned to meet the 1981 summer peak load forecast is 20,644 megawatts. No new generating capacity is expected to be available for the summer peak season, but it is anticipated that two of the three units at the Brayton Point Plant of the New England Electric System that are being converted from oil to coal fuel will be completed prior to the summer peak. However, the major portion of the NEPOOL generation is oil-fired and represents 54% of the energy generated in July 1980, while nuclear-fueled generation represented 37%. Table 6A.2 indicates projected generation by fuel type for July 1981 based on ERA-Form 160, and actual data for July 1980. Table 6A.3 provides fuel use projections for oil and gas for July 1981 and actual use for July 1980. Table 6A.4 shows the average generating capacity unavailable at the time of the summer peak for the period 1977-1980 based on the data submitted on the FPC Form 12E-2.

The NEPOOL calculated scheduled maintenance based on a four year summer average and summarized in Table 6A.4 is 8.0%. The four year summer forced outage rate is 8.6% and the four year summer average of other unavailable capability is 7.3%. These are shown in Table 6.1, lines 9, 13 and 17, as the outages that might be experienced during the summer season.

As shown in Table 6.1 for summer 1981, the NEPOOL Region will have adequate reserves to meet its load responsibility. Planned reserves are 39.7%, and actual reserves, after scheduled maintenance, forced outages and other unavailable capability, are 8.7%. During the summer season, no transmission problems should be experienced unless there is an unexpected generating unit forced outage for a protracted period, coupled with a transmission line outage.

New York Power Pool
Electric Region 4

The New York Power Pool (NYPP) coordinates the planning and operation of the eight major electric utility systems in New York State, and is the only pool in the contiguous U.S. where the Electric Region and geographic region are defined by the state boundary.

The State of New York is summer peaking. Although the northern portion of the State has a winter peak, the larger loads of the downstate utilities cause the overall state peak to occur in the summer. The peak forecast for the summer 1981 is 21,063 megawatts. This is a 4.2% decrease below the previous summer and 9% higher than the winter peak. The summer peak growth in NYPP has been depressed over the last three years, reflecting load conservation, mild summers and depressed economic conditions. Planned capability to meet the coming summer peak load is 30,363 megawatts. No major additions of capacity are expected prior to the summer season. New York, while not being quite as dependent on fuel oil as New England, generated 36% of its electric energy from oil in July 1980. Hydro-electric capacity, the bulk of which is from the St. Lawrence and Niagara projects of the Power Authority of the State of New York, represented 22% of July 1980 generation. Nuclear, coal, and gas fired generation were 15%; 12%; and 15% respectively.

Table 6B.2 provides projected generation by fuel type for July 1981, based on Form ERA-160 and actual data for July 1980. Table 6B.3 compares actual 1980 (July) use of oil and gas (Electric Power Monthly for August 1980) with projected 1981 (July) data from the ERA Form 160. Gas-fired generation is expected to decrease substantially while nuclear generation will take up the slack for the month of July 1981. The use of fuel oil for the past four years has decreased in the NYPP; coal use is predicted to increase. Oil use is projected to remain approximately constant.

Table 6B.4 shows the average generating capacity unavailable at the time of the summer system peak for the past four summers and the four year average. Scheduled maintenance over the past four summer seasons averaged 7.5%, forced outages averaged 8.6% and other unavailable capacity 5.0%. Scheduled maintenance requirements over the past four years has shown a marked increase from 5.5% of installed capacity in 1977 to 10% in 1980. The reason for the increase is the annual refueling and maintenance of nuclear units during the summer on systems in the state that peak during the winter. Additionally, in 1980 there was unusual maintenance performed on several large generating units of Niagara Mohawk Power Company (Oswego #5, and the Huntley and Dunkirk Units).

As indicated on Table 6.1 for summer 1981, the NYPP Region should have actual reserves of about 16.2%, which is adequate to meet its load responsibility. The NYPP reserve criterion calls for a planned reserve of 22% before effect is given to the net of imports and exports and to possible outages of capacity; Table 6.1 shows the planned reserve is 44.2%.

It is expected that the repairs necessitated by the accident at Indian Point No. 2 Nuclear Unit, salt water intrusion into the reactor vessel, will be completed in time to make the unit available for service during the summer peak period.

Lack of adequate North-to-South transmission capacity prevents economic dispatch of some New York Power Pool resources during off-peak hours in the summer peak period. Northwestern New York has lower-cost capacity available during those hours, from NYPP units and from Ontario Hydro, that could be utilized elsewhere in the State. However, transmission constraints prevent transfer of this power to other areas. Additional and alternate transmission facilities, planned and under construction, are expected to alleviate this situation.

TABLE 6.1

NORTHEAST POWER COORDINATING COUNCIL (NPCC)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR THE SUMMER 1981 PEAK PERIOD

	NEW ENGLAND POWER POOL (NEPOOL)	NEW YORK POWER POOL (NYPP)	TOTAL NPCC[1] REGION
1. PLANNED CAPABILITY (MW)	20644	30363	51007
2. PEAK DEMAND (MW) [2]	14780	21063	35843
3. PLANNED RESERVES (MW)(1-2)	5864	9300	15164
4. PLANNED RESERVES (%) (3/2) X 100	39.7	44.2	42.3
5. NET TRANSACTIONS (IMPORTS - EXPORTS) (MW) [2]	362	520	882
6. TOTAL CAPABILITY (MW) (1+5)	21006	30883	51889
7. TOTAL RESERVES (MW) (6-2)	6226	9820	16046
8. TOTAL RESERVES (%) (7/2) X 100	42.1	46.6	44.8
9. SCHEDULED MAINTENANCE (MW) [3]	1652	2277	3929
10. CAPABILITY AFTER MAINTENANCE (MW) (6-9)	19354	28606	47960
11. RESERVES AFTER MAINTENANCE (MW) (10-2)	4574	7543	12117
12. RESERVES AFTER MAINTENANCE (%) (11/2) X 100	30.9	35.8	33.8
13. FULL FORCED OUTAGES (MW) [4]	1775	2611	4386
14. AVAILABLE CAPABILITY AFTER FORCED OUTAGES (MW)(10-13)	17579	25995	43574
15. AVAILABLE RESERVES (MW) (14-2)	2799	4932	7731
16. AVAILABLE RESERVES (%) (15/2) X 100	18.9	23.4	21.6
17. OTHER UNAVAILABLE CAPABILITY (MW) [5]	1507	1518	3025
18. AVAILABLE CAPABILITY (MW) (14-17)	16072	24477	40549
19. ACTUAL RESERVES (MW) (18-2)	1292	3414	4706
20. ACTUAL RESERVES (%) (19/2) X 100	8.7	16.2	13.1

[1] ALL LIAISON MEMBER SYSTEMS HAVE BEEN INCORPORATED WITH APPROPRIATE BULK POWER MEMBER SYSTEMS. FOR THE PURPOSE OF THIS REPORT.

[2] THE NYPP & NPCC PEAK AS REPORTED IN THE FORM 411 HAS BEEN REDUCED BY 107 MW TO REFLECT A DELIVERY BY PASNY TO MAAC FOR ALLEGHENY ELECTRIC COOP. THIS DELIVERY IS NOT REPORTED IN THE NPCC FORM 411.

[3] COMPUTED AT THE FOUR YEAR AVERAGE SUMMER SCHEDULED MAINTENANCE RATE (FPC FORM 12E-2)

[4] COMPUTED AT THE FOUR YEAR AVERAGE SUMMER FORCED OUTAGE RATE. (FPC FORM 12E-2)

[5] OTHER UNAVAILABLE CAPABILITY IS PARTIAL UNIT FORCED OUTAGES, DERATINGS AND THAT WHICH IS OUT OF SERVICE FOR LACK OF FUEL OR MANPOWER, OR HAS BEEN DEACTIVATED AND COULD REQUIRE SEVERAL WEEKS TO BE PUT ON LINE. COMPUTED AT THE FOUR YEAR AVERAGE UNAVAILABLE CAPABILITY RATE.

TABLE 6.2

ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
NORTHEAST POWER COORDINATION COUNCIL

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
HYDRO	2,323,000	14.3	2,295,076	14.5
COAL	1,572,000	9.6	1,685,200	10.7
GAS	1,578,000	9.7	1,193,830	7.6
OIL	6,961,000	42.9	6,807,130	43.2
NUCLEAR	3,807,000	23.4	3,910,902	24.8
PUMP STORAGE (NET)	NA	NA	(140,000)	(0.9)
OTHER	2,000	0.1	16,000	0.1
TOTAL	16,243,000	100.0	15,768,138	100.0

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6.3

GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
NORTHEAST POWER COORDINATION COUNCIL

FUEL TYPE	JULY 1981 PROJECTION	JULY 1980 ACTUAL	PERCENTAGE 7-81/7-80
GAS (MCF)	13,272 *	18,302	72.5
OIL (BBLS)	11,575,779	11,558,000	100.2

* INCLUDES 1,243 MCF PROPANE

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6.4

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE SUMMER SYSTEM PEAK DEMAND 1977,1978,1979,1980
NORTHEAST POWER COORDINATION COUNCIL

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
JULY 1977	4154	7.9	3916	7.5	3408	6.5
AUG. 1978	4117	7.8	4376	8.3	3123	5.9
AUG. 1979	3460	6.3	6351	11.6	3444	6.3
JULY 1980	4796	8.7	3838	7.0	2921	5.3
4-YR. AVERAGE		7.7		8.6		6.0

SOURCE: FPC FORM 12E-2

TABLE 6A.2
ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
NEW ENGLAND POWER POOL

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
HYDRO	161,000	2.5	217,776	3.8
COAL	378,000	5.8	525,000	9.0
GAS	87,000	1.3	-	-
OIL	3,539,000	53.9	3,371,138	58.1
NUCLEAR	2,400,000	36.5	1,739,202	29.9
PUMP STORAGE (NET)	NA	NA	(46,000)	(0.8)
OTHER	3,000	0.0	-	-
TOTAL	6,568,000	100.0	5,807,116	100.0

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6A.3

GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
NEW ENGLAND POWER POOL

FUEL TYPE	JULY 1981 PROJECTION	JULY 1981 ACTUAL	PERCENTAGE 7-81/7-80
GAS (MCF)	1,243 *	1,078	115.3
OIL (BBLS)	5,721,546	5,873,000	97.4

* PROPANE

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6A.4

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE SUMMER SYSTEM PEAK DEMAND 1977,1978,1979,1980
NEW ENGLAND POWER POOL

MONTH-YEAR	SCHEDULED MAINTENANCE		FULL FORCED OUTAGES		OTHER UNAVAILABLE CAPACITY	
	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY	(MW)	% OF INSTALL CAPACITY
JULY 1977	2438	11.7	928	4.4	1677	8.0
AUG. 1978	2026	9.9	1999	9.7	1750	8.5
AUG. 1979	827	3.9	2477	11.7	1537	7.3
JULY 1980	1402	6.7	1748	8.3	1323	6.3
4-YR. AVERAGE		8.0		8.6		7.3

SOURCE: FPC FORM 12E-2

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TABLE 6B.2

ACTUAL AND PROJECTED GENERATION BY FUEL TYPE
NEW YORK POWER POOL

FUEL TYPE	ACTUAL JULY 1980 GENERATION (MWH)	% OF TOTAL	PROJECTED JULY 1981 GENERATION (MWH)	% OF TOTAL
HYDRO	2,159,000	22.3	2,077,300	20.8
COAL	1,193,000	12.3	1,160,200	11.6
GAS	1,491,000	15.4	1,193,830	12.0
OIL	3,422,000	35.4	3,435,992	34.5
NUCLEAR	1,407,000	14.6	2,171,700	21.8
PUMP STORAGE (NET)	NA	NA	(94,000)	(0.9)
OTHER	-	-	16,000	0.2
TOTAL	9,672,000	100.0	9,961,022	100.0

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST
PROJECTED DATA - ERA FORM 160

TABLE 6B.3

GAS AND OIL USE PROJECTION FOR JULY 1981
VS
ACTUAL GAS AND OIL USE FOR JULY 1980
NEW YORK POWER POOL

FUEL TYPE	JULY 1981 PROJECTION	JULY 1980 ACTUAL	PERCENTAGE 7-81/7-80
GAS (MCF)	12,029	17,224	69.8
OIL (BBLS)	5,854,233	5,686,000	102.96

SOURCE: ACTUAL DATA - ELECTRIC POWER MONTHLY - AUGUST 1980
PROJECTED DATA - ERA FORM 160

TABLE 6B.4

AVERAGE GENERATING CAPACITY UNAVAILABLE AT THE TIME OF THE
SUMMER SYSTEM PEAK DEMAND 1977,1978,1979,1980
NEW YORK POWER POOL

MONTH-YEAR	SCHEDULED MAINTENANCE (MW)	SCHEDULED MAINTENANCE % OF INSTALL CAPACITY	FULL FORCED OUTAGES (MW)	FULL FORCED OUTAGES % OF INSTALL CAPACITY	OTHER UNAVAILABLE CAPACITY (MW)	OTHER UNAVAILABLE CAPACITY % OF INSTALL CAPACITY
JULY 1977	1716	5.5	2987	9.5	1731	5.5
AUG. 1978	2091	6.5	2377	7.4	1373	4.3
AUG. 1979	2633	7.8	3874	11.5	1907	5.6
JULY 1980	3394	10.0	2090	6.2	1598	4.7
4-YR. AVERAGE		7.5		8.6		5.0

SOURCE: FPC FORM 12E-2

7.0 SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL (SERC)

The Southeastern Electric Reliability Council (SERC) is comprised of four Electric Regions. Electric Region 7 covers Peninsular Florida and is represented by the Florida Electric Coordinating Group (FCG). Electric Region 9 is referred to as the Southern Company Group and its service area covers the Florida Panhandle, the southeastern quadrant of Mississippi, the southern three-fourths of Alabama, and all except a small portion of Georgia. Electric Region 11 is represented by the Tennessee Valley Authority (TVA) and serves all of Tennessee, the northeastern quadrant of Mississippi, three Cooperatives in north Georgia and southwestern portion of North Carolina, a small portion of Southwest Kentucky, and the northern quarter of Alabama. The fourth SERC group is Electric Region 12; it is referred to as the Virginia-Carolinas Group (VACAR) and serves South Carolina, all except a small Southwest portion of North Carolina, the Virginia Electric and Power Company's service area in Virginia and three counties in West Virginia.

A brief review of the actual conditions in the SERC area during last summer's record heat wave is appropriate prior to an analysis of the "Estimated Summer 1981 Electric Demand and Supply" situation. The recorded 1980 summer peaks for July and August exceeded the greatest previously recorded summer peak by 7.9 and 6.1 percent respectively. During the three month summer season of June, July and August, the net energy requirements increased by 7.1 percent. Table 7.1 shows the actual demand and supply situation for the summer 1980 peak month for each of the four Electric Regions in SERC. Table 7.2 shows the corresponding data as projected for summer 1981, with Planned Capability, Peak Demand and Net Transactions taken from the SERC ERA-411 report dated April 1, 1981.

Table 7.1
Southeastern Electric Reliability Council (SERC)
Tabulation of Actual Load and Supply
for Summer 1980 Peak Period 1/

Mw or Percent	Florida	Southern	TVA	VACAR	SERC
(1) Planned Capability	22,554	25,083	27,063	33,842	108,542
(2) Peak Demand	18,171 2/	22,690 2/	20,250 2/	29,029 3/	90,140
(3) Planned Reserve	4,383	2,393	6,813	4,813	18,402
(4) Planned Reserve (%)	24.1	10.5	33.6	16.6	20.4
(5) Net Transactions	606	3,298	485	4,189	8,578
(6) Total Capability	23,160	28,381	27,548	38,031	117,120
(7) Total Reserve	4,989	5,691	7,298	9,002	26,980
(8) Total Reserve (%)	27.5	25.1	36.0	31.0	29.9
(9) Scheduled Maint.	1,347	157	255	4,025	5,784
(10) Capability after Main	21,813	28,224	27,293	34,006	111,336
(11) Reserve after Maint.	3,642	5,534	7,043	4,977	21,216
(12) Reserve aft Maint. (%)	20.0	24.4	34.8	17.1	23.5
(13) Forced Outage	997	3314	4,738	537	9,586
(14) Avail. Cap. aft. F.O.	20,816	24,910	22,555	33,469	101,750
(15) Available Reserve	2,645	2,220	2,305	4,440	11,610
(16) Available Reserve (%)	14.6	9.8	11.4	15.3	12.9
(17) Other Unavailable	853	304	1,282	3,253	5,692
(18) Available Capability	19,963	24,606	21,273	30,216	96,058
(19) Actual Reserve	1,792	1,916	1,023	1,187	5,918
(20) Actual Reserve (%)	9.9	8.4	5.1	4.1	6.6

1/ From FPC Form 12E-2
2/ July 1980
3/ August 1980

Table 7.2
Southeastern Electric Reliability Council
Tabulation of Estimated Load and Supply for Summer 1981 Peak Period

Mw or Percent	Florida	Southern	TVA	VACAR	SERC
(1) Planned Capability	24,529	27,975	28,232	36,333	117,069
(2) Peak Demand	18,577	21,101 2/	19,669	29,302 3/	88,649
(3) Planned Reserve	5,952	6,874	8,563	7,032	28,420
(4) Planned Reserve (%)	32.0	32.6	43.5	24.0	32.1
(5) Net Transactions	0 1/	140	(1100)	900	(60)
(6) Total Capability	24,529	28,115	27,132	37,233	117,009
(7) Total Reserve	5,952	7,014	7,463	7,931	28,360
(8) Total Reserve (%)	32.0	33.2	37.9	27.1	32.0
(9) Scheduled Maint.	1,840	503	395	2,144	4,882
(10) Capability after Main	22,689	27,612	26,737	35,089	112,127
(11) Reserve after Maint.	4,112	6,511	7,068	5,787	23,478
(12) Reserve aft Maint. (%)	22.1	30.9	35.9	19.7	26.5
(13) Forced Outage	908 4/	1,734	2,908	2,107	7,657 4/
(14) Avail. Cap. aft. F.O.	21,781	25,878	23,829	32,982	104,470
(15) Available Reserve	3,204	4,777	4,160	3,680	15,821
(16) Available Reserve (%)	17.2	22.6	21.2	12.6	17.8
(17) Other Unavailable	908	1,007	1,327	2,834	6,076
(18) Avail. Cap.	20,873	24,871	22,502	30,148	98,394
(19) Actual Reserve	2,296	3,770	2,833	846	9,745
(20) Actual Reserve (%)	12.4	17.9	14.4	2.9	11.0

1/ 400 Mw Non-firm available from Southern Company
2/ Includes 211 Mw of interruptible load.
3/ Includes 165 Mw of interruptible load.
4/ Does not include Turkey Point 3, 646 MW.

Table 7.3
Southeastern Electric Reliability Council Regions
Capacity Unavailable at Time of Summer Peak
As Percentage of Installed Capacity 1/

	Florida	Southern	TVA	VACAR
Scheduled Maintenance	7.5	1.8	1.4	5.9
Full Forced Outage	3.7	6.2	10.3	5.8
Other Unavailable	3.7	3.6	4.7	7.8

1/ Based on data reported in FPC Form 12E-2 for the years 1977 through 1980.

Table 7.3 provides the percentages that were applied to the Planned Capability of Line 1 in Table 7.2 to obtain the unavailable Capability shown on Lines 9, 13 and 17.

The SERC forecast peak demands for the Summer 1981 season shown on Table 7.2, project an increase of 6.8 percent over the actual 1979 summer peak, the last summer having "normal" summer temperatures. This is an average annual growth of about 3.3 percent for the two year period and is consistent with the historic trend of recent years. The usual amount of load diversity was not experienced in summer 1980 because of a widespread, prolonged heat storm coupled with a significant amount of weather-sensitive load. The 1981 summer peakload forecast, however, reflects a normal load growth over the 1979-81 period with a normal diversity factor. This will be discussed more fully for each Electric Region.

Table 7.4
Southeastern Electric Reliability Council
Three year Load Growth Profile

Region	1979	1980	1981 1/
Florida	16,605	18,171	18,577
Southern	20,432	22,690	21,101
TVA	18,795	20,250	20,016
VACAR	27,492	29,029	29,302
SERC	83,324	90,140	88,966

1/ Forecast from ERA 411.

Fuel Use

Fuel use is a concern in each of the four regions in SERC with each region having its own potentially critical problem. This will be discussed in more detail in the individual section for each region. Table 7.5 shows the projected generation by fuels for the 1981 Summer peak for the SERC Region.

Table 7.5
Southeastern Electric Reliability Council
Projected Generation by Fuels for Summer 1981 Peak Month

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	2,562,028	5.6
Coal	26,112,868	57.4
Gas	1,417,179	3.1
Oil	6,031,232	13.2
Nuclear	9,399,692	20.7
Other	14,600	Neg.
Total	45,537,599	100.0

Table 7.6 compares fuel consumption for the Summer 1980 and the projected consumption for the Summer 1981 for the more critical gas and oil fuels. Part of the decreased usage can be attributed to a projected return to normal summer temperatures with a reduction in the use of gas turbin peaking units.

Table 7.6
Southeastern Electric Reliability Council
Peak Month Fuel Use Projected for Summer 1981
Versus Actual for Summer 1980

Fuel Type	Summer 1981 Projection	Summer 1980 Actual	Percent of Change Summer '81 vs. Summer '80
Gas (Mcf)	16,426,000	19,719,379	(16.7)
Oil (Bbl)	10,625,512	10,834,562	(1.9)

Transmission

Figure 7.1 shows the SERC Subregion EHV interconnecting lines, maximum transfer capacity 1/ and schedule power transfers for the summer 1981 peak load season.

Table 7.7 summarizes scheduled power transfers and transmission import capacities for each Subregion of SERC for the 1981 summer peak load situation.

Table 7.7
Southeastern Electric Reliability Council
Summary of Transmission Transfers and Import Capacity
Summer 1981

SERC Subregion	Import Capacity in Mw	Scheduled Imports in Mw	Unused Import in Mw
Florida	800	400 2/	400
Southern	5,000	140	4,460
TVA	6,700	0	5,600
VACAR	5,150	900	4,250
SERC 3/	8,650	1,860	6,790

1/ Maximum transfer capacity is estimated based on typical circuit voltage load-carrying volumes. Lines which loop through another organization's service area and change ownership but do not have an injection mode where additional power can enter or leave are not considered interconnecting lines in this analysis. In the case of three terminal interconnections, the capability was divided between interconnecting parties.

2/ Non-firm transfer.

3/ Non-Simultaneous Total. This differs from the sum of the regional amounts because of the different timing of peak load conditions among the regions and the nature of power flows among areas with multiple interconnections.

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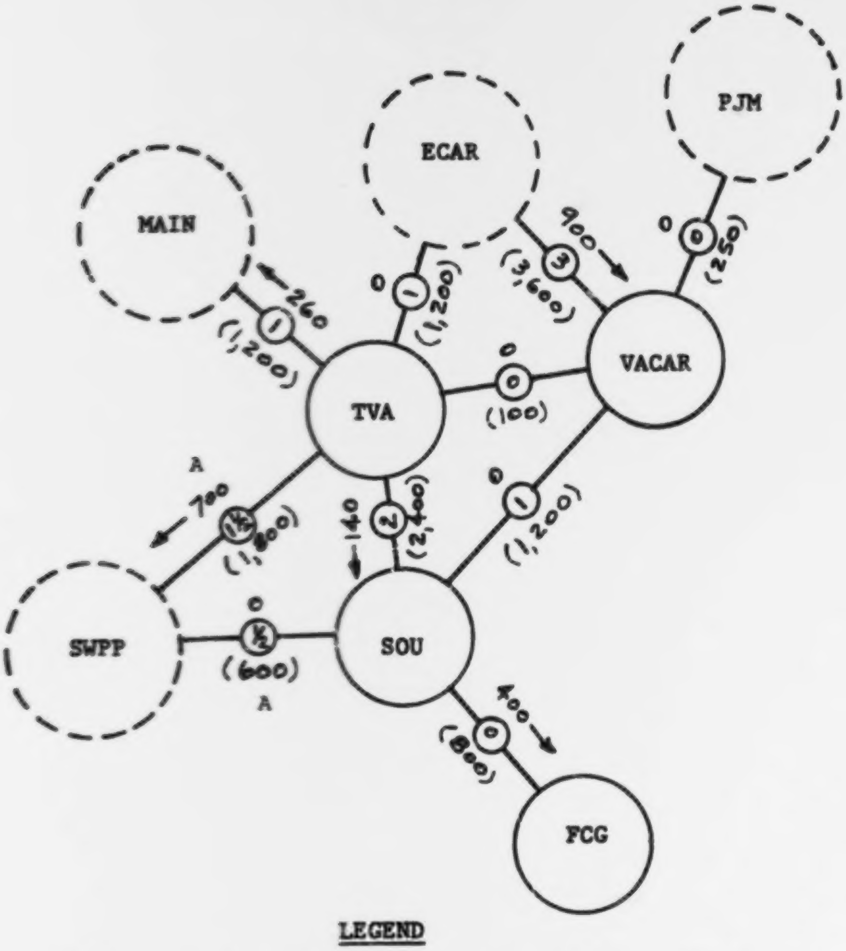
Figure 7.1

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

SERC Subregion Scheduled Power Transfers and Transfer Capacity

Summer 1981


PJM
ECAR
MAIN
TVA
VACAR
SWPP
SOU
FCG
260
1
(1,200)
0
1
(1,200)
900
3
(3,600)
0
0
(250)
0
0
(100)
A
700
1½
(1,800)
140
2
(2,400)
0
1
(1,200)
0
½
(600)
A
400
0
(800)

LEGEND

──②── Number of Interconnecting Lines at 500 kv or Higher Voltage.

300 → Scheduled Firm Power Transfer in Mw.
(1200) Maximum Transfer Capability in Mw. 1/

1/ Based on typical circuit capability of 1,200 Mw per circuit for 500 kv.

A - SWPP, TVA and Southern share a single line and a 3-terminal line. The diagram is not a physical representation but attempts only to indicate the power flow condition.

Florida Coordinating Group (FCG) Region

The FCG region has the heaviest dependency on oil in the SERC area, accounting for 88 percent of the total oil consumption in SERC. Because of this, nuclear units play an important role in the upcoming summer season as well as the near future as the region explores new methods of reducing oil consumption. Table 7A.1 shows the projected generation by fuels for July 1981 and Table 7A.2 compares fuel use for July 1980 with projected use for July 1981.

Table 7A.1
Florida Coordinating Group Region
Projected Generation by Fuels for July 1981

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	0	0
Coal	1,395,100	14.9
Gas	1,186,300	12.7
Oil	5,305,142	56.8
Nuclear	1,444,020	15.4
Other	14,600	0.2
Total	9,345,432	100.0

Table 7A.2
Florida Coordinating Group Region
Fuel Use Projected for July 1981
Versus Actual for July 1980

Fuel Type	July 1981 Projection	July 1980 Actual	Percent of Change July 1981 vs. July 1980
Gas (Mcf)	13,782,000	14,550,191	(5.3)
Oil (Bbl)	9,088,466	8,116,699	12.0

While the three other Electric Regions making up the SERC area experienced average 1980 summer temperatures ranging from 3.1 to 5.2 degrees above normal, the temperatures for the FCG area were well within the normal expectancy for the summer months. However, owing to the duration of the "heat wave" and its cumulative effects, the 1980 summer peak exceeded the previous year by 9.1 percent and the energy requirements increased by 5.6 percent. A comparison of the 1980 summer peak load shown on Table 7.1 with the 1981 peak load forecast shown on Table 7.2, projects a growth of 2.2 percent for this year. The FCG is also projecting a 3.1 percent increase in energy requirements. These projections for load and energy growth appear consistent with current normal growth rates for the FCG area.

As currently scheduled, the only new capability anticipated to be available for the summer load is the Gainesville Regional Utilities Deerhaven No. 2, 235 Mw coal-fired unit. This would increase the reserve shown on Table 7.2 to 2,531 Mw, or 13.6 percent.

The recent long-term outage of Turkey Point No. 3 reduces the prospect of reliable service in Florida.

Southern Company Group (SOU) Region

The Southern Company Region has the greatest energy production by coal as a percent of total production among the SERC Electric Regions. The complete summation of generation by fuel types is shown on Table 7B.1.

Table 7B.1
Southern Company Group Region
Projected Generation By Fuels For August 1981

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	339,900	3.2
Coal	8,096,418	75.6
Gas	209,679	2.0
Oil	98,620	0.9
Nuclear	1,962,080	18.3
Other	0	0
Total	10,706,697	100.0

The SOU is a summer peaking area where last year's record summer temperature resulted in a peak demand that was 24 percent higher than the winter peak. Table 7B.2 shows summer energy and weather data for 1979 (a normal weather period) and 1980. The 12.3% increase in energy for July and August, considered in relation to the 25.0% increase in cooling degree-days, indicates significant weather-sensitivity. Peak demand in the 1980 summer was about 10.8 percent greater than it was in 1979.

Table 7B.2
Southern Company Group Region
Comparison of 1980 Versus 1979 Summer Degree Days Temperature and Energy

	Avg. Deg. Days		% Change	Avg. Temp. 1/		Energy (Gwh)		
	1980	1979	1980 vs. 1979	1980	1979	1980	1979	% Change
July	556	436	27.5	83.0	79.0	11,516	9980	15.4
August	520	425	22.4	81.8	78.7	11,434	10,458	9.3
Total	1,076	861	25.0	82.4	78.9	22,950	20,438	12.3

1/ U.S. Weather Service defines each 1.5 degrees variation from normal as a deviation. 1979 was considered a normal year.

Except for the possible curtailment of coal deliveries, the SOU appears to be in excellent shape for the 1981 Summer season. The 1981 peak load forecast actually reflects a 5.9 percent decrease over 1980. Energy requirements for this year show the same percent decrease.

The following units are currently scheduled to come on line this summer:

Utility	Unit	Mw	Fuel	In Service Date
Alabama Power Co.	Farley-2	807	Nuclear	July 1981
Mississippi Power Co.	Daniel-2	252 1/	Coal	June 1981
Gulf Power Co.	Daniel-2	252 1/	Coal	June 1981

1/ Jointly owned.

The above units are not included in the planned capability shown on Table 7.2. If these units should be available for the summer peak, the actual reserves shown on line 20 of Table 7.2 would be increased to about 21.6%.

Tennessee Valley Authority (TVA) Region

TVA is the largest system in the SERC area, serving municipalities and cooperatives with service areas in seven states. In keeping with its original concept, TVA has many multi-purpose hydroelectric projects and produces 15.7 percent of its total energy requirements by this means. Table 7C.1 shows the complete summary of generation by fuels.

Table 7C.1
Tennessee Valley Authority Region
Projected Generation by Fuels for July 1981

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	1,562,400	15.7
Coal	7,648,300	68.9
Gas	0	0
Oil	0	0
Nuclear	1,711,200	15.4
Other	0	0
Total	11,100,900	100.0

The TVA area had the greatest increase in the average temperature for the summer of 1980 of any of the four Electric Regions in SERC. The average temperature difference of 5.2 degrees as derived from Table 7C.2 amounts to approximately 3.5 deviations as defined by the U.S. Weather Service. Although the degree days increased by 49.2 percent, the net energy for the 1980 summer period only increased by 7.3 percent over the 1980 summer and the demand increased 7.7 percent. The small increase in energy requirements apparently reflects the effects of TVA conservation programs. The load growth, which averaged about 280 Mw per degree temperature rise above normal, appears consistent with TVA load forecasting projections.

Table 7C.2
Tennessee Valley Authority Region
Comparison of 1980 Versus 1979 Summer Degree Days
Temperature and Energy

	Avg. Deg. Days		% Change	Avg. Temp.		Energy (Gwh)		
	1980	1979	1980 vs. 1979	1980	1979	1980	1979	% Change
July	499	329	51.7	81.1	75.6	11,208	10,202	9.9
August	472	322	46.6	80.2	75.4	11,011	10,508	4.8
Total	971	651	49.2	80.7	75.5	22,219	20,710	7.3

From May 1980 through the winter of 1980-81, the TVA area has experienced its worst drought in 91 years of record keeping. While conditions have improved this spring, hydroelectric power supply could still be considered somewhat uncertain at this time.

After adjustment for the unusual weather conditions in the summer of 1980, the peak demand shown on Table 7.2 projects a reduction of about 2.9 percent for the 1981 summer peak. TVA also projects a reduction of about 3 percent for energy requirements.

The only new capability anticipated for the summer load will be the Sequoyah No. 1, 1148 Mw nuclear unit. It should be noted, however, that only about 600 Mw will be available. The Sequoyah capability is included in Table 7.2. After being unavailable for several months on full forced outage, the Cumberland No. 2, coal-fired, 1275 Mw unit returned to service the first week in April 1981. This leaves TVA in a good load/supply situation for the 1981 summer season, even in view of possible difficulties with hydro capacity supply.

Virginia-Carolinas Group (VACAR) Region

On the basis of energy requirements and peak demand, VACAR is the largest of the four electric regions making up the Southeastern Electric Reliability Council. The projected generation by fuel to meet these requirements is shown in Table 7D.1.

Table 7D.1
Virginia-Carolinas Group Region
Projected Generation by Fuels for August 1981

Type Fuel	Generation (Mwh)	Percent of Total
Hydro	480,728	3.3
Coal	8,973,050	62.4
Gas	21,900	0.2
Oil	627,200	4.3
Nuclear	4,282,292	29.8
Other	0	0
Total	14,385,170	100.0

Nuclear energy plays a large role in reducing the use of oil in the VACAR region and also in reducing the cost of energy. Based on a SERC-wide comparison, VACAR generates 44 percent of the total nuclear energy. Table 7D.2 shows a comparison between the actual Summer 1980 use of gas and oil and the projected use for Summer 1981. There is a sharp decrease in the use of these two fuels. In fact, this decrease in oil usage exceeds the increased usage in the FCG region and results in an overall reduction in the SERC area as shown on Table 7.6.

Table 7D.2
Virginia-Carolinas Group Region
Fuel Use Projected for August 1981 Versus Actual for August 1980

Fuel Type	August 1981 Projection	August 1980 Actual	Percent August '81 / August '80
Gas (Mcf)	258,000	2,978,821	8.7
Oil (Bbls)	1,223,826	2,496,771	49.0

Table 7D.3 shows temperature conditions and energy requirements for 1979 and 1980. The peakload for the same period increased 5.6 percent.

Table 7D.3
Virginia-Carolinas Group Region
Comparison of 1980 Versus 1979 Summer Degree Days
Temperature and Energy

	Avg. Deg. Days		% Change	Avg. Temp. 1/		Energy (Gwh)		
	1980	1979	1980 vs. 1979	1980	1979	1980	1979	% Change
July	448	336	33.3	79.5	75.8	14,503	12,809	13.2
August	435	361	20.5	79.0	76.6	14,996	13,913	7.8
Total	883	697	26.7	79.3	76.2	29,499	26,722	10.4

The projected energy requirements for July-August 1981 are 28,684 Gwh, a decrease of about 2.8 percent. It is projected that the peak demand will increase by one percent over last year.

The following units are currently scheduled to come on-line this summer.

Utility	Unit	Mw	Fuel	In Service Date 1/
Duke Power Company	McGuire No. 1	1180	Nuclear	July 1981
South Carolina Public Service Auth.	Winyah No. 4	280	Coal	June 1981

1/ ERA-411 - April 1981

These units, if available, would improve the reserve situation shown on Table 7.2. However, it is not certain how much capability can be expected from the McGuire unit. While the load/supply situation in VACAR could be "tight" this summer, it should be noted from Figure 7.1 that transmission capacity is available for importing power.

8. Southwest Power Pool (SPP)

The Southwest Power Pool (SPP) includes all of the states of Arkansas, Kansas, Louisiana, and Oklahoma and part of the states of Mississippi, Missouri, New Mexico, and Texas. The SPP area is divided into three Regions: Region 8 (Middle South-Gulf States Group) 1/, Region 21 (Missouri-Kansas Group) and Region 22 (Oklahoma Group).

Region 8 encompasses most of Arkansas, all of Louisiana, about one-half of Mississippi, a small portion of southwest Missouri and the east central portion of Texas.

Region 21 covers almost the entire state of Kansas and the remaining part of Missouri that is in the SPP. The majority of the electric systems operating in Region 21 are members of the MOKAN Power Pool.

Region 22 includes all of Oklahoma and portions of Arkansas, Kansas, Louisiana, Texas, and New Mexico.

Table 8.1 shows the 1981 summer peak load and supply analysis for Regions 8, 21 and 22, as well as the SPP. Data was obtained from the SPP ERA-411 report to DOE dated April 1, 1981. Planned Capability in Line 1 of Table 8.1 differs from that shown in Item 3-A of SPP's ERA-411. The DOE staff calculated Planned Capability by totalling all of the existing capacity listed in Item 2-A and added the proposed capacity changes shown in Item 2-B. Capacity changes scheduled after May 31 were not included as dependable capability available to serve a portion of the 1981 summer peak. SPP included units scheduled for service in June and sometimes July in their calculations. The DOE criteria are somewhat more stringent than SPP's, however, due to the possibility that the summer peak could occur in June and that unit installations could be delayed. DOE determined that the May 31 cutoff date was appropriate for this report.

SPP reports that no maintenance has been scheduled by any of its three Regions for the summer peak period. Historic data show that actual scheduled maintenance has been minimal. Estimates of full forced outages and other unavailable capability are based on historical percent averages. The four year averages (1977-1980) were calculated from information furnished by the electric systems in FPC Form 12E-2 and are based on forced outages and other unavailable capability at the time of the summer peak. These historical percentages are 6.1 percent of installed capability for full forced outages and 2.4 percent for other unavailable capability.

The actual reserve for the SPP as shown in Table 8.1 during the summer of 1981 amounts to 12.3 percent which includes the effect of 4,523 MW of total capability unavailable to serve load.

The SPP appears to have adequate capability to supply the upcoming summer peak demand.

Figure 8.1 indicates the 1981 summer non-simultaneous emergency (first contingency) transfer capabilities between SPP and adjacent reliability councils. Also included are the scheduled firm power transfers between councils as well as the number of

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1/ Region 8 includes what were formerly Regions 8 and 10.

ties operating at 230 kV or above. High voltage ties between Electric Regions are also included. A 500-kV tie between Region 8 and Region 21 is projected for June 1981, but will operate initially at 161-kV, and therefore is not shown.

All of the Electric Regions within the SPP are summer-peaking. The ratios of the projected 1981-82 winter peak to the projected 1981 summer peak for Regions 8, 21 and 22 are .76, .73 and .71, respectively.

The summer of 1980 was extremely hot and dry throughout the SPP area and the load in each of the three Regions is quite sensitive to temperature due to the high saturation of refrigeration type air conditioners. This followed an abnormally cool summer in 1979; with the net result being a high rate of load growth between the summers of 1979 and 1980. The estimates of peak demands shown for the summer of 1981 in Table 8.1 are based on average summer temperature conditions resulting in a very low estimated load growth between 1980 and 1981. The actual percent load growth between the summers of 1979 and 1980 and the estimated percent load growth between 1980 and 1981 are listed for each Electric Region and the SPP in the following table:

	Actual Summer Load Growth 1/ 1979-1980 (Percent)	Estimated Summer Load Growth 2/ 1980-1981 (Percent)
Region 8	10.4	-5.7
Region 21	14.9	0.6
Region 22	14.9	1.1
SPP	12.8	-2.1

1/ Based on information from FPC 12E-2 reports.
2/ Calculated from data furnished in April 1981 ERA-411 report.

Should the weather conditions in 1981 approach those experienced during the summer of 1980 and a corresponding load growth occurs, total reserve for the SPP would decline to 6.6 percent of peak demand and actual reserves would be a negative 2.3 percent. Summer 1981 total and actual reserves (see lines 8 and 20, respectively, of Table 8.1) for each Electric Region, assuming the same load growth in 1981 that occurred in 1980, are shown in the following table:

Electric Region	Total Reserves (1981) (Percent of Peak Demand)	Actual Reserves (1981) (Percent of Peak Demand)
8	4.6	-6.7
21	7.3	-3.3
22	9.2	4.8

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The Middle South-Gulf States Group (Region 8) is strongly dependent on gas-fueled generation. During the 1981 summer peak 63.2 percent of its generating capability will be from gas, 19.0 percent from oil, 9.7 percent from coal, 7.7 percent from nuclear, and 0.3 percent from hydro.

Table 8.1 shows Region 8 actual reserves to be 9.1 percent or 1,794 MW during the 1981 summer peak. This includes no scheduled maintenance, 8.6 percent full forced outages and 3.1 percent other unavailable capability. Estimated full forced outages amount to 1,899 MW. DOE has been informed by the Louisiana Power & Light Company that forced outages have been experienced on Little Gypsy No. 2 and Ninemile No. 4, which amount to 1,105 MW. These units are not expected to be back in service by May 31, 1981.

Based upon the 9.1% actual reserves Region 8 should have adequate capacity to supply the 1981 summer peak demand. Fuel supplies should not be affected barring any unforeseen occurrence.

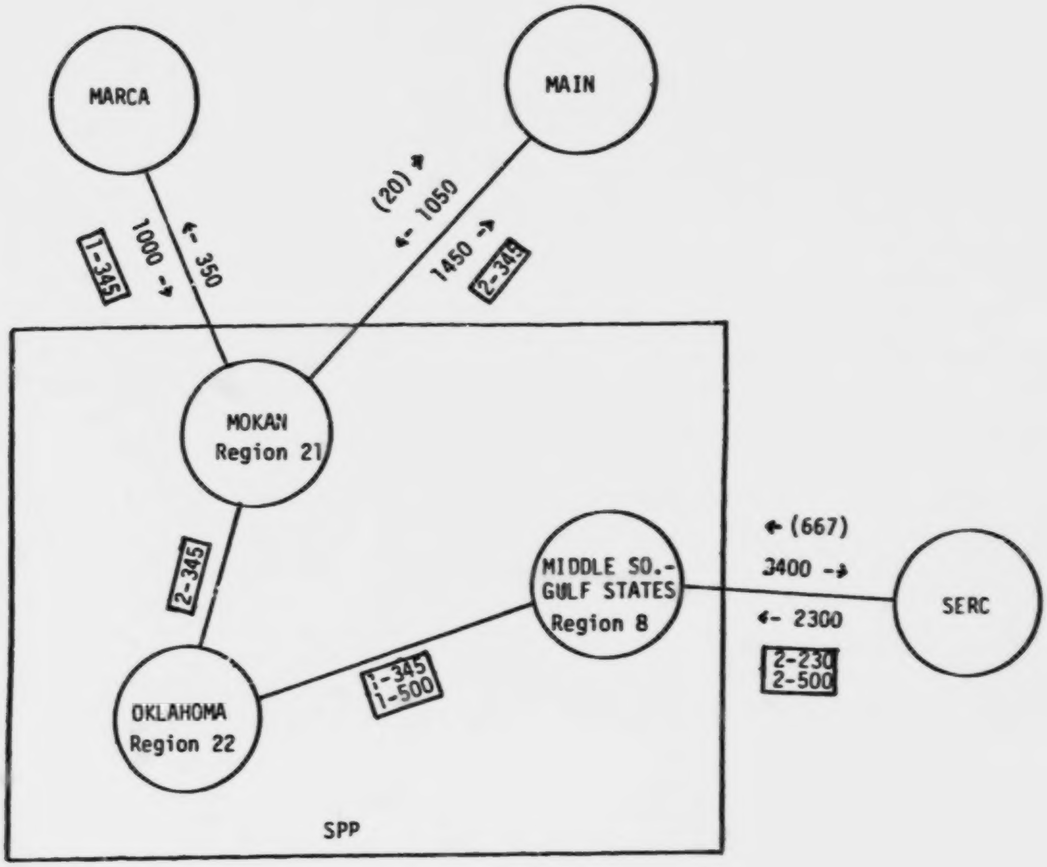
Region 21 (Missouri-Kansas Group) has a projected actual reserve margin of 9.3 percent. This figure includes no scheduled maintenance, 6.8 percent full forced outages, and 3.3 percent other unavailable capability. Region 21 should have an ample capacity reserve for the upcoming summer peak period.

Unlike the rest of the SPP, Region 21 is dependent on coal for its generation. It has 8,454 MW of coal-fired capacity (68.7 percent of its total capability).

The Oklahoma Group (Region 22) shows a very high actual reserve margin of 19.1 percent. Included in this figure is zero scheduled maintenance, 2.8 percent full forced outages, and 0.9 percent other unavailable capability. Region 22 is dependent on natural gas for its generation (10,869 MW or 57.7 percent of total).

Region 22 appears to have adequate capacity, as well as ample fuel supply, to handle the projected 1981 summer peak load and its net export of 1424 MW.

TRANSFER CAPABILITIES
BETWEEN SPP ELECTRIC REGIONS AND ADJACENT RELIABILITY COUNCILS
1981 SUMMER PEAK


MARCA
MAIN
1-345
1000 →
← 350
(20) →
← 1050
1450 →
2-345
MOKAN
Region 21
2-345
MIDDLE SO.-
GULF STATES
Region 8
← (667)
3400 →
← 2300
2-230
2-500
SERC
1-345
1-500
OKLAHOMA
Region 22
SPP

(20) → Net Firm Power Transfer in Megawatts
1000 → First Contingency Incremental Transfer Capability in Megawatts
2-345 Number of Interconnections and Kilovolts (230-kV and Above)

Figure 8.1

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TABLE 8.1

SOUTHWEST POWER POOL (SPP)

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD

MW OR PERCENT	MIDDLE SOUTH GULF STATES GROUP	MISSOURI KANSAS GROUP (MOKAN)	OKLAHOMA GROUP	TOTAL SPP REGION
1. PLANNED CAPABILITY	22084	12310	18830	53224
2. PEAK DEMAND	19643	10461	14030	44134
3. PLANNED RESERVES (1-2)	2441	1849	4800	9090
4. PLANNED RESERVES (%) (3/2)X100	12.4	17.7	34.2	20.6
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	1937	367	-1424	880
6. TOTAL CAPABILITY (1+5)	24021	12677	17406	54104
7. TOTAL RESERVES (6-2)	4378	2216	3376	9970
8. TOTAL RESERVES (%) (7/2)X100	22.3	21.2	24.1	22.6
9. SCHEDULED MAINTENANCE	0	0	0	0
10. CAPABILITY AFTER MAINTENANCE (6-9)	24021	12677	17406	54104
11. RESERVES AFTER MAINTENANCE (10-2)	4378	2216	3376	9970
12. RESERVES (%) AFTER MAINTENANCE (11/2)X100	22.3	21.2	24.1	22.6
13. FULL FORCED OUTAGES 1/	1899	837	527	3263
14. CAPABILITY AFTER FULL FORCED OUTAGES (10-13)	22122	11840	16879	50841
15. RESERVES AFTER FULL FORCED OUTAGES (14-2)	2479	1379	2849	6707
16. RESERVES (%) AFTER FULL FORCED OUTAGES (15/2)X100	12.6	13.2	20.3	15.2
17. OTHER UNAVAILABLE CAPABILITY 1/ 2/	685	406	169	1260
18. ACTUAL CAPABILITY (14-17)	21437	11434	16710	49581
19. ACTUAL RESERVES (18-2)	1794	973	2680	5447
20. ACTUAL RESERVES (%) (19/2)X100	9.1	9.3	19.1	12.3

1/ OTHER UNAVAILABLE CAPABILITY AND FULL FORCED OUTAGES ARE CALCULATED USING THE HISTORICAL PERCENT AVERAGES AT THE TIME OF THE SUMMER AND WINTER PEAKS BEGINNING WITH THE 1977 SUMMER.
DATA OBTAINED FROM FPC FORM 12E-2.

2/ OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGES.

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9. WESTERN SYSTEMS COORDINATING COUNCIL (WSCC)

The Western Systems Coordinating Council (WSCC) area includes systems in the Canadian Provinces of British Columbia and Alberta, the States of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, most of the states of Montana and New Mexico, and small sections of the States of South Dakota and Texas. However, Canadian systems are excluded from this report. WSCC, the largest geographically of the nine Regional Councils, consists of five Electric Regions. These subregions are:

24 Rocky Mountain Power Area (RMPA)
25 Northwest Power Pool (NWPP) (NWPP/A + NWPP/B) 1/
26 Arizona-New Mexico Group (A-NM)
27 Southern California-Nevada Group (SC-N)
28 Northern California Nevada Group (NC-N)

For WSCC the projected non-coincidental peak load of 79,039 MW for the summer season represents a 6.1 percent increase over the 1980 summer peak. The estimated total reserves shown in Table 9.1 are 25.8 percent. In the various subregions the estimated total reserves range from a low of 9.3 percent for the Northern California-Nevada Power Area to a high of 33.7 percent in the Northwest Power Pool Area. In addition to scheduled maintenance, this report includes the estimated effects of forced outages and other unavailable capability based on a historical four-year average. Considering these possible outages the actual reserves could range from a low of 1.3 percent to a high of 23.6 in the five subregions and actual reserves for WSCC could drop to 11.5 percent. Planned capability shown in Table 9.1 is based on adverse year hydro capabilities. Actual water conditions are considered in subregional analyses following.

Fuel supplies for WSCC are projected to be adequate for the summer season. However, transmission limitations and circulating power flow (loop flow) throughout the WSCC interconnected system can adversely affect the ability to transfer coal-fired generation for oil displacement.

The transfer capabilities shown in Figure 9.1 represent the total capability of the various interconnections. Scheduled firm power transfers are the contractual obligations in effect during the summer peak month of August. It should be noted that these firm schedules do not include the availability of surplus or economy energy. Also, there is a strong possibility that the Northern California-Nevada Area may purchase firm capacity from the Southern California-Nevada Area during the 1981 summer period because of the continuing delay in licensing of the Diablo Canyon nuclear power plant.

The remaining unused capacity of the various interconnections is used for:

(1) purchasing economy energy,
(2) exchanging emergency power,
(3) interconnection reserve support of 600 MW between the Northern California-Nevada and Southern California-Nevada Areas,
(4) accommodating major loop circulating flow.

Rocky Mountain Power Area
(Electric Region 24)

The Rocky Mountain Power Area (RMPA) is projected to experience a 3.9 percent increase in summer peak demand over 1980. The Area's annual peak historically has occurred during either winter or summer. The annual peak for 1980 occurred during the summer although the 1980-81 winter peak was nearly the same.

1/ NWPP/A = West Group; NWPP/B = East Group

Scheduled commercial operation of Public Service Co. of Colorado's Pawnee No. 1, 470 MW, has been deferred from January to December 1981 due to financing problems and construction delays. Without Pawnee No. 1 the Area's actual projected reserve margin of 21.3% is still considered to be adequate.

Curtailments of generation in Northwest Colorado may be required to maintain system stability under certain conditions due to the delays of the Wolcott-Basalt 230 kV line (now Dec. 1981) and the related Basalt-Malta (October 1982) 230 kV line. These delays are expected to have minimal overall effect.

Northwest Power Pool Area
(Electric Region 25)

In the Northwest Power Pool Area (NWPP) a winter peaking area, the 1981 summer peak load is projected to be 26,890 MW. This represents a 14.1 percent increase over the 1980 summer peak. The projected growth appears high considering that the previous two years' summer peak demand growth rates were 3.3 and 2.4 percent. Conservation and a general economic slump apparently are still influencing load growth. The actual reserve margin is estimated at 12.1 percent, after allowance for a large amount of scheduled maintenance.

The NWPP is predominantly hydro-dependent with about 73 percent of its generating capability in hydroelectric generating plants. Consequently, the Area's power supply is very much affected by the annual precipitation and snowpack. The annual spring snowpack runoff determines to a great extent the reservoir storage that will be available for the summer and winter seasons. Also, the hydro conditions will determine the amount of secondary energy (energy over and above firm loads) that may be available for sale outside the Area. Planning is done to meet forecasted firm loads based on adverse year hydro capability.

The April 1 preliminary forecast of January-July Columbia River runoff as measured at The Dalles, Oregon was 78.6 million acre-feet or 71.5 percent of the most recent 15 year average. Reservoir storage at the end of March was reported to be very close to the level required for refill this summer. However, Bonneville Power Administration's preliminary studies indicate that after the fisheries operation, which begins in late April, the reservoirs may not refill completely. Availability of secondary energy during the summer is expected to be very limited.

Portland General Electric Company's Trojan Nuclear plant, 1080 MW, was shut down May 1 for refueling and maintenance. It is expected to be back in service July 8.

Delays in construction of Idaho Power Company's Kinport-Midpoint ID, 345 kV line and Pacific Power & Light Company's Midpoint, ID-Malin, OR 500 kV line has limited the transfer of Wyoming's coal-fired resources to the West Group area of the NWPP. However, scheduled maintenance in Wyoming will reduce the availability of coal-fired generation for transfer during the summer. No significant effect on the reliability of the bulk power transmission system is expected. The two lines are now scheduled to be in service by October 1981.

Arizona-New Mexico Power Area
(Electric Region 26)

The Arizona-New Mexico Power Area is forecasted to experience a 6.2 percent increase in the 1981 summer peak demand over that of 1980. For this summer peaking Area an actual reserve margin of 23.6 percent is projected.

Arizona Public Service Company's Cholla Unit No. 4, 347 MW, scheduled for commercial operation in June 1981, combined with existing capacity will provide 7,511 MW of coal-fired generating capability or 56 percent of the Area's total capability.

The Arizona-New Mexico Power Area does not have a formal installed reserve criterion. Area reserve planning is done on an individual utility basis. The total Area reserve margin is considered sufficient and projected fuel supplies and transmission interconnections are expected to be adequate for the 1981 summer season. However, loop flow problems may limit transfers of economy energy to California for purposes of oil displacement.

Southern California-Nevada Area
(Electric Region 27)

Total reserve margins appear adequate for the Southern California-Nevada Area. In recent years unit outage rates have been extraordinarily high throughout California because of aging plants and considerable usage during tight supply situations thus reducing actual reserves. However, the projected actual reserve for the summer peak remains adequate at eleven percent.

The Southern California-Nevada Power Area is predominantly summer peaking. The projected 1981 peak demand represents only a 0.4 percent increase over last summer's actual peak. Although weather conditions were generally mild last summer, the lack of intra-regional load diversity resulted in a higher than expected combined peak demand for the Area.

San Onofre Nuclear Unit No. 1, 436 MW, has been out of service since April 1980 due to extended maintenance and is currently expected on-line just prior to summer. This outage could conceivably be extended into the peak months. Also, excessive inadvertent major transmission loop flow is a recurring problem for Southern California utilities. This situation may limit importation of firm capacity and energy from resources located east of the Area. These supply limitations coupled with other unexpected occurrences could limit the Southern California utilities' ability to assist Northern California if deficiencies develop in that Area.

Northern California-Nevada Power Area
(Electric Region 28)

The projected actual reserve margin of 1.3% for the Northern California-Nevada Power Area is well below the level required to ensure system supply reliability. The forecasted peak demand represents a 2.4 percent growth rate over 1980 for this summer peaking Area. The major factor contributing to the inadequate supply is the continued delay in operation of Pacific Gas and Electric Company's (PG&E) Diablo Canyon Nuclear Units No. 1 and No. 2 (2190 MW capability). Unit No. 1, 1084 MW, previously scheduled for service in July 1981, is now estimated to be in service in January, 1982.

Hydroelectric capacity constitutes approximately 37 percent of the Northern California-Nevada generating capability and the figures incorporated in Table 9.1 are based on adverse water conditions. Hydroelectric plant generation is presently expected to be closer to normal this summer thus increasing somewhat the associated plant capabilities.

California utilities have updated their summer forecasts utilizing actual water and snowpack conditions and recent information on the availability of thermal-electric units and projected loads. The resultant estimated acual reserve margins for the PG&E planning area (which serves approximately 95 percent of the Northern California-Nevada Power Area load) indicate a minimum of 2.1 percent [1] during the expected peak month of July. These data include a 157 MW capability reduction of Sacramento Municipal Utility District's Rancho Seco Nuclear Unit due to turbine blade problems.

Additional short-term capacity purchases totalling approximately 1000 MW, which are not included in Table 9.1 reserve margin calculations, could be available from outside the Area. The majority of these purchases would be from utilities in the Southern California-Nevada Power Area.

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[1] This is an improvement over the 1.3 percent shown on line 20 of Table 9.1 for the Northern California-Nevada Area.

A statewide plan for reserve sharing and load deferral[1] has been developed by the major California utilities. Briefly, the reserve sharing plan obligates utilities to share reserves when the actual reserve margin of a utility drops below 7 percent. When reserve margins drop to 5 percent a statewide "Peak Day Alert" declaration and public appeals would occur. Actual reserves of 3 percent would result in shedding interruptible loads and intensified appeals; and when margins drop to 1.5 percent or below rotating circuit interruptions would take place.

Many factors can affect the actual reliability situation during a period of tight supply. Factors on the positive side include the availability of short-term capacity purchases, load diversity, limited forced outage, mild weather, and customer conservation. Conversely, factors which could lead to load curtailments in California this summer include higher than forecasted peak demand, high forced outage, lack of load diversity, and the unavailability of short-term purchases or loss of a major interconnection.

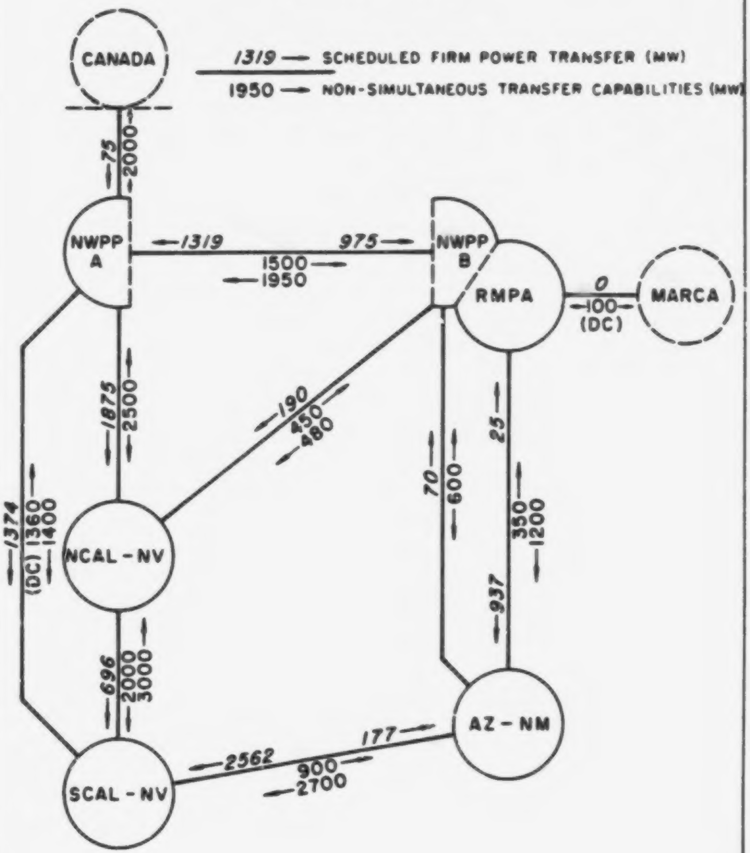
Fuel supplies for thermal-electric plants are adequate for the period.

1/ Load shedding is considered to be, to some extent, a deferral of load in that some energy requirements not served due to supply interruption will be served at a later time.

FIGURE 9.1

WESTERN SYSTEMS COORDINATING COUNCIL

SUBREGION SCHEDULED POWER TRANSFERS
SUMMER 1981


CANADA
1319 — SCHEDULED FIRM POWER TRANSFER (MW)
1950 — NON-SIMULTANEOUS TRANSFER CAPABILITIES (MW)
75
2000
NWPP A
1319
975
1500
1950
NWPP B
RMPA
0
100
(DC)
MARCA
1875
2500
190
450
480
70
600
25
350
1200
937
1374
(DC)
1360
1400
NCAL-NV
696
2000
3000
177
2562
900
2700
AZ-NM
SCAL-NV

NOTES NWPP/A = West Group of Northwest Power Pool

NWPP/B = East Group of Northwest Power Pool

Italicized numbers above line show scheduled firm power transfer. Numbers below line show non-simultaneous transfer capability.
Each line is symbolic only, and may represent one or more transmission circuits.

TABLE 9.1

WESTERN SYSTEMS COORDINATING COUNCIL (WSCC) [2]

TABULATION OF ESTIMATED LOAD AND SUPPLY FOR SUMMER 1981 PEAK PERIOD [5]

MW OR PERCENT	ROCKY MOUNTAIN POWER AREA	NORTHWEST POWER POOL AREA	ARIZONA-NEW MEXICO POWER AREA	SOUTHERN CALIFORNIA -NEVADA POWER AREA	NORTHERN CALIFORNIA -NEVADA POWER AREA	TOTAL WSCC REGION
1. PLANNED CAPABILITY	7845	39222	13404	22020	16859	99350
2. PEAK DEMAND	5338	26890	8960	21189	16662	79039
3. PLANNED RESERVES (1-2)	2507	12332	4444	831	197	20311
4. PLANNED RESERVES (%) (3/2)X100	47.0	45.9	49.6	3.9	1.2	25.7
5. NET TRANSACTIONS (IMPORTS-EXPORTS)	-951	-3257	-1542	4442	1358	50
6. TOTAL CAPABILITY (1+5)	6894	35965	11862	26462	18217	99400
7. TOTAL RESERVES (6-2)	1556	9075	2902	5273	1555	20361
8. TOTAL RESERVES (%) (7/2)X100	29.1	33.7	32.4	24.9	9.3	25.8
9. SCHEDULED MAINTENANCE [4]	25	3745	0	878	0	4648
10. CAPABILITY AFTER MAINTENANCE	6869	32220	11862	25584	18217	94752
11. RESERVES AFTER MAINTENANCE (10-2)	1531	5330	2902	4395	1555	15713
12. RESERVES AFTER MAINTENANCE (%) (11/2)X100	28.7	19.8	32.4	20.7	9.3	19.9
13. FULL FORCED OUTAGE [3]	149	981	550	947	303	2930
14. CAPABILITY AFTER FORCED OUTAGE (10-13)	6720	31239	11312	24637	17914	91019
15. RESERVE AFTER FORCED OUTAGE (14-2)	1382	4349	2352	3448	1252	11980
16. RESERVE AFTER FORCED OUTAGE (%) (15/2)X100	25.9	16.2	26.2	16.3	7.5	15.2
17. OTHER UNAVAILABLE CAPABILITY [1]	243	1098	241	1123	1028	3733
18. ACTUAL CAPABILITY (14-17)	6477	30141	11071	23514	16886	88089
19. ACTUAL RESERVES (18-2)	1139	3251	2111	2325	224	9050
20. ACTUAL RESERVES (%) (19/2)X100	21.3	12.1	23.6	11.0	1.3 [6]	11.5

[1] OTHER UNAVAILABLE CAPABILITY IS THAT CAPABILITY WHICH IS UNAVAILABLE FOR LOAD FOR REASONS OTHER THAN SCHEDULED MAINTENANCE OR FULL FORCED OUTAGE.

[2] CANADIAN SYSTEMS ARE EXCLUDED.

[3] COMPUTED BY FOUR YEAR AVERAGE FORCED OUTAGE RATE FROM 12E-2 DATA FOR 1977-1980 SUMMERS.

[4] AS REPORTED BY THE WSCC.

[5] CAPABILITY DATA REFLECT ADVERSE HYDRO CONDITIONS.

[6] RECENTLY AVAILABLE HYDRO INFORMATION INDICATES THIS RESERVE MAY APPROACH 2.1%.

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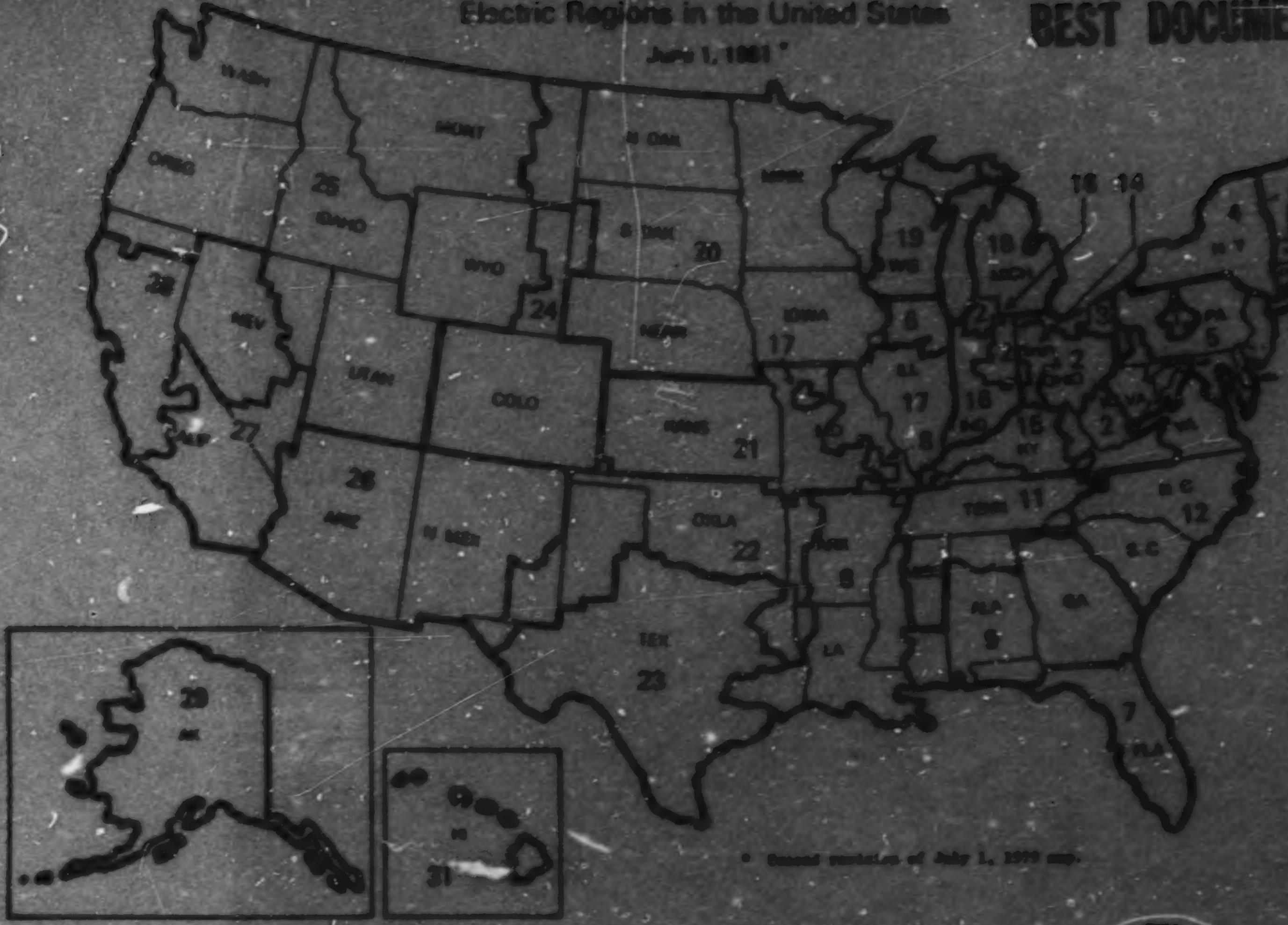
Department of Energy

Electric Regions in the United States

June 1, 1981 *


WASH
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Reliability Council

ECAR -East Central Area Reliability Coordination Agreement

ERCOT -Electric Reliability Council of Texas

MAAC -Mid-Atlantic Area Council

MAIN -Mid-America Interpool Network

MARCA -Mid-Continent Area Reliability Coordination Agreement

NPCC -Northeast Power Coordinating Council

SERC -Southeastern Electric Reliability Council

SPP -Southwest Power Pool

WSCC -Western Systems Coordinating Council

* Second revision of July 1, 1979 map.

Electric Region		Identification
	ECAR	
1		Allegheny Power System (APS)
2		American Electric Power System (AEP)
13		Central Area Power Coordination Group (CAPCO)
14		Cincinnati, Dayton Group (CD)
15		Kentucky Group
16		Indiana Group - All Indiana Utilities except I&M Electric Co.
18		Michigan Electric Coordinated Systems (MECS)
	ERCOT	
23		Texas Interconnected Systems Group (TIS)
	MAAC	
5		Pennsylvania-New Jersey-Maryland Interconnection (PJM)
	MAIN	
6		Commonwealth Edison Co.
17		Illinois-Missouri Group (ILLMO)
19		Wisconsin-Upper Michigan Systems Group (WUMS)
	MARCA	
20		Mid-Continent Area Power Pool (MAPP)
	NPCC	
3		New England Power Pool (NEPOOL)
4		New York Power Pool (NYPP)
	SERC	
7		Florida Coordinating Group (FCG)
8		Southern Company Group
11		Tennessee Valley Authority Group (TVA)
12		Virginia-Carolinas Group (VACAR)
	SPP	
9		Middle South Utilities/ Gulf States Utilities Group
21		Missouri-Kansas Group (MOKAN)
22		Oklahoma Group
	WSCC	
24		Rocky Mountain Power Pool (RMPP)
25		Northwest Power Pool (NWPP)
26		Arizona-New Mexico Group
27		Southern California-Nevada Group
28		Northern California-Nevada Group

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